GUIDANCE NOTE
ON
INTERNAL AUDIT OF POWER SECTOR

Internal Auditing and Assurance Standards Board

The Institute of Cost Accountants of India

(Statutory Body under an Act of Parliament)

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List of Acronyms/Abbreviations used			
AAD	Advance Against Depreciation	AAQM	Ambient Air Quality Monitoring
ABT	Availability Based Tariff	AC	Alternating Current
ACQ	Annual Contracted Quantity	ACS	Average Cost of Supply
AERB	Atomic Energy Regulatory Board	AFC	Annual Fixed Charges
AG	Accountant General	AI	Artificial Intelligence
AIDC	Agriculture Infrastructure and Development Cess	AMD	Acid Mine Drainage
AMISP	Advanced Metering Infrastructure Service Provider	APC	Auxiliary Power Consumption
APM	Administered Price Mechanism	APTEL	Appellate Tribunal for Electricity
ARR	Annual Revenue Requirement; Average Revenue Realised (in ACS–ARR gap)	AT&C	Aggregate Technical and Commercial (Loss)
ATC	Annual Transmission Charges	ATN	Action Taken Note
ATR	Action Taken Report	AY	Assessment Year
BCCL	Bharat Coking Coal Limited	BCD	Basic Customs Duty
BCM	Bank Cubic Metre	BEE	Bureau of Energy Efficiency
BESS	Battery Energy Storage System	BG	Bank Guarantee
BIS	Bureau of Indian Standards	BMS	Battery Management System
BOCW	Building and Other Construction Workers	BRSR	Business Responsibility and Sustainability Report
CA	Compensatory Afforestation	CAG	Comptroller and Auditor General of India
CARO	Companies (Auditor's Report) Order	CAS	Cost Accounting Standards
CBAM	Carbon Border Adjustment Mechanism	CCC	Carbon Credit Certificate
CCCCE	Criteria, Condition, Cause, Consequence, Corrective action	CCL	Central Coalfields Limited
CCO	Coal Controller's Organisation	CCTS	Carbon Credit Trading Scheme
CCTV	Closed-Circuit Television	CEA	Central Electricity Authority
CEMS	Continuous Emission Monitoring System	CERC	Central Electricity Regulatory Commission
CERT-In	Indian Computer Emergency Response Team	CGRF	Consumer Grievance Redressal Forum
CGST	Central Goods and Services Tax	CIA	Chief Internal Auditor
CIF	Cost, Insurance and Freight	CII	Critical Information Infrastructure

List of Acronyms/Abbreviations used			
CIL	Coal India Limited	CIMFR	Central Institute of Mining and Fuel Research
CIRP	Cybersecurity Incident Response Plan	CMA	Cost and Management Accountant
CMD	Chairman and Managing Director	COD	Commercial Operation Date
COPU	Committee on Public Undertakings	CPCB	Central Pollution Control Board
CPI	Consumer Price Index	CPSE	Central Public Sector Enterprise
CPSU	Central Public Sector Undertaking	CSR	Corporate Social Responsibility
CTE	Consent to Establish	CTO	Consent to Operate
CTU	Central Transmission Utility	CTUIL	Central Transmission Utility of India Limited
CUF	Capacity Utilisation Factor	CVC	Central Vigilance Commission
CWC	Central Water Commission	DAM	Day Ahead Market
DBT	Direct Benefit Transfer	DC	Declared Capacity; Designated Consumer (PAT)
DCS	Distributed Control System	DFP	Delegation of Financial Powers
DGMS	Directorate General of Mines Safety	DISCOM	Distribution Company
DMF	District Mineral Foundation	DNS	Domain Name System
DPDP	Digital Personal Data Protection (Act)	DPE	Department of Public Enterprises
DPR	Detailed Project Report	DSCR	Debt Service Coverage Ratio
DSM	Deviation Settlement Mechanism	DSRA	Debt Service Reserve Account
DSRP	Dam Safety Review Panel	DT	Distribution Transformer
EAP	Emergency Action Plan	EC	Environmental Clearance
ECB	External Commercial Borrowings	ECBC	Energy Conservation Building Code
ECEA	Electricity Contract Enforcement Authority	ECL	Eastern Coalfields Limited
ECR	Electronic Challan cum Return	ECSBC	Energy Conservation and Sustainable Building Code
ED	Electricity Duty	EMP	Environmental Management Plan
EMS	Energy Management System	EPC	Engineering, Procurement and Construction
EPF	Employees' Provident Fund	EPFO	Employees' Provident Fund Organisation
EPR	Extended Producer Responsibility	ERP	Enterprise Resource Planning

List of Acronyms/Abbreviations used			
ESCert	Energy Savings Certificate	ESG	Environmental, Social and Governance
ESI	Employees' State Insurance	ESIC	Employees' State Insurance Corporation
ESO	Energy Storage Obligation	ESP	Electrostatic Precipitator
ETP	Effluent Treatment Plant	EU	European Union
EV	Electric Vehicle	FAR	Fixed Asset Register
FC	Forest Clearance	FEMA	Foreign Exchange Management Act
FGD	Flue Gas Desulphurisation	FIFO	First In First Out
FIR	First Information Report	FM	Force Majeure
FOR	Free on Rail	FPA	Fuel Price Adjustment
FPPCA	Fuel and Power Purchase Cost Adjustment	FSA	Fuel Supply Agreement
FY	Financial Year	GAIL	GAIL (India) Limited
GCV	Gross Calorific Value	G-DAM	Green Day Ahead Market
GeM	Government e-Marketplace	GENCO	Generation Company
GHG	Greenhouse Gas	GNA	General Network Access
GPS	Global Positioning System	GRC	Governance, Risk and Compliance
Grid-India	Grid Controller of India Limited	GSA	Gas Supply Agreement
GST	Goods and Services Tax	GSTN	Goods and Services Tax Network
GSTR	Goods and Services Tax Return	GTA	Gas Transmission Agreement
GW	Gigawatt	GWP	Global Warming Potential
HEMM	Heavy Earth Moving Machinery	HES	Head End System
HFO	Heavy Fuel Oil	HP-DAM	High Price Day Ahead Market
HPO	Hydro Purchase Obligation	HPX	Hindustan Power Exchange
HR	Human Resources	HSN	Harmonised System of Nomenclature
HT	High Tension	HVAC	Heating, Ventilation and Air Conditioning
IA	Internal Audit	IAAS	Internal Audit and Assurance Standards
IAASB	Internal Auditing and Assurance Standards Board	IACS	Industrial Automation and Control System
IAD	Internal Audit Department	IAEA	International Atomic Energy Agency
IBR	Indian Boiler Regulations	ICC	Internal Complaints Committee
ICMAI	Institute of Cost Accountants of India	ICT	Information and Communication Technology

List of Acronyms/Abbreviations used			
IDC	Interest During Construction	IE	Independent Engineer
IEC	International Electrotechnical Commission	IEGC	Indian Electricity Grid Code
IEX	Indian Energy Exchange	IFAC	International Federation of Accountants
IGST	Integrated Goods and Services Tax	IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer	IR	Inspection Report
ISSA	International Standard on Sustainability Assurance	ISTS	Inter-State Transmission System
IT	Information Technology	ITC	Input Tax Credit
ITD	Income Tax Department	ITR	Income Tax Return
JERC	Joint Electricity Regulatory Commission	JV	Joint Venture
KPI	Key Performance Indicator	KYC	Know Your Customer
LC	Letter of Credit	LD	Liquidated Damages
LDC	Load Despatch Centre	LDO	Light Diesel Oil
LNG	Liquefied Natural Gas	LoA	Letter of Assurance (SHAKTI coal linkage)
LODR	Listing Obligations and Disclosure Requirements	LPS	Late Payment Surcharge
LT	Low Tension	LTA	Long Term Access
MAFR	Master Audit Findings Register	MB	Measurement Book
MCA	Ministry of Corporate Affairs	MCL	Mahanadi Coalfields Limited
MDO	Mine Developer and Operator	MMDR	Mines and Minerals (Development and Regulation) Act 1957
MNRE	Ministry of New and Renewable Energy	MoC	Ministry of Coal
MoEFCC	Ministry of Environment, Forest and Climate Change	MoP	Ministry of Power
MoU	Memorandum of Understanding	MRV	Monitoring, Reporting and Verification
MSME	Micro, Small and Medium Enterprises	MTOA	Medium Term Open Access
MU	Million Units	M&V	Measurement and Verification
MW	Megawatt	MWh	Megawatt-hour

List of Acronyms/Abbreviations used			
MYT	Multi-Year Tariff	NABL	National Accreditation Board for Testing and Calibration Laboratories
NAPAF	Normative Annual Plant Availability Factor	NBPPL	NTPC-BHEL Power Projects Private Limited
NCIIPC	National Critical Information Infrastructure Protection Centre	NCL	Northern Coalfields Limited
NCR	National Carbon Registry	NDAIAPA	National Designated Authority for the Implementation of the Paris Agreement
NDC	Nationally Determined Contribution	NEP	National Electricity Plan
NESCL	NTPC Electric Supply Company Limited	NGT	National Green Tribunal
NHPC	NHPC Limited	NIC	National Informatics Centre
NIT	Notice Inviting Tender	NLC	NLC India Limited
NLDC	National Load Despatch Centre	NMET	National Mineral Exploration Trust
NO_x	Oxides of Nitrogen	NPCIL	Nuclear Power Corporation of India Limited
NPL	National Physical Laboratory	NPP	National Power Portal
NPV	Net Present Value	NRV	Net Realisable Value
NTP	Network Time Protocol	NTPC	NTPC Limited
NVVN	NTPC Vidyut Vyapar Nigam	OB	Overburden
OCEMS	Online Continuous Emission Monitoring System	OEM	Original Equipment Manufacturer
O&M	Operation and Maintenance	OSH	Occupational Safety, Health and Working Conditions (Code)
OT	Operational Technology	PAC	Public Accounts Committee
PAF	Plant Availability Factor	PAN	Permanent Account Number
PAP	Project Affected People	PAT	Perform, Achieve and Trade
PESO	Petroleum and Explosives Safety Organisation	PF	Provident Fund
PFC	Power Finance Corporation	PG	Performance Guarantee
PGCIL	Power Grid Corporation of India Limited	PIO	Public Information Officer
PLF	Plant Load Factor	PMKKKY	Pradhan Mantri Khanij Kshetra Kalyan Yojana

List of Acronyms/Abbreviations used			
PM-KUSUM	Pradhan Mantri Kisan Urja Suraksha evam Utthaan Mahabhiyan	PNGRB	Petroleum and Natural Gas Regulatory Board
PoC	Point of Connection	POSH	Prevention of Sexual Harassment (of Women at Workplace)
PPA	Power Purchase Agreement	PR	Performance Ratio
PSP	Pumped Storage Project	PSU	Public Sector Undertaking
PT	Professional Tax	PUC	Pollution Under Control
PXIL	Power Exchange India Limited	QAIP	Quality Assurance and Improvement Programme
RA	Regulatory Asset	RBI	Reserve Bank of India
RBIA	Risk-Based Internal Audit	RCM	Reverse Charge Mechanism
RDSS	Revamped Distribution Sector Scheme	RE	Renewable Energy
REC	Renewable Energy Certificate	RFCTLARR	Right to Fair Compensation and Transparency in Land Acquisition, Rehabilitation and Resettlement Act 2013
RLDC	Regional Load Despatch Centre	R&M	Renovation and Modernisation
ROC	Registrar of Companies	ROE	Return on Equity
RoW	Right of Way	RPO	Renewable Purchase Obligation
RPT	Related Party Transaction	RR	Railway Receipt
R&R	Resettlement and Rehabilitation	RTC	Round-the-Clock
RTE	Round Trip Efficiency	RTI	Right to Information
RTM	Real Time Market	SBI	State Bank of India
SCADA	Supervisory Control and Data Acquisition	SCCL	Singareni Collieries Company Limited
SCED	Security Constrained Economic Despatch	SCN	Show Cause Notice
SCSR	Self-Contained Self-Rescuer	SEBI	Securities and Exchange Board of India
SEC	Specific Energy Consumption	SECI	Solar Energy Corporation of India Limited
SECL	South Eastern Coalfields Limited	SERC	State Electricity Regulatory Commission

List of Acronyms/Abbreviations used			
SGST	State Goods and Services Tax	SHAKTI	Scheme for Harnessing and Allocating Koyala (Coal) Transparently in India
SHR	Station Heat Rate	SIA	Social Impact Assessment
SIGHT	Strategic Interventions for Green Hydrogen Transition	SJVN	SJVN Limited
SLDC	State Load Despatch Centre	SMP	Safety Management Plan
SO_2	Sulphur Dioxide	SOC	Specific Oil Consumption
SoC	State of Charge	SoD	Segregation of Duties
SOP	Standard Operating Procedure	SoP	Standards of Performance
SPCB	State Pollution Control Board	SPV	Special Purpose Vehicle
SRAS	Secondary Reserve Ancillary Services	STU	State Transmission Utility
SWS	Social Welfare Surcharge	TAM	Term Ahead Market
TBCB	Tariff Based Competitive Bidding	TDS	Tax Deducted at Source
THDC	THDC India Limited	toe	Tonne of Oil Equivalent
TOTEX	Total Expenditure (model)	TP	Transfer Pricing
TRANSCO	Transmission Company	TRAS	Tertiary Reserve Ancillary Services
TSA	Transmission Service Agreement	UAN	Universal Account Number
UC	Utilisation Certificate	UI	Unscheduled Interchange
UMPP	Ultra Mega Power Project	VAPT	Vulnerability Assessment and Penetration Testing
VO	Variation Order	VPP	Virtual Power Plant
VVB	Validation and Verification Body	WCL	Western Coalfields Limited
WPI	Wholesale Price Index	ZLD	Zero Liquid Discharge

ABOUT THIS GUIDANCE NOTE

Origin and Purpose

This Guidance Note on Internal Audit of Power Sector has been prepared by the Internal Auditing and Assurance Standards Board (IAASB) of the Institute of Cost Accountants of India (ICMAI). It is intended to serve as a comprehensive and practical reference for Cost and Management Accountants (CMAs) and other professionals engaged in the internal audit of entities across India's power sector.

The power sector is one of the most regulated, capital-intensive, and operationally complex industries in India. It involves a unique combination of technical operations, extensive regulatory oversight, significant public funds, and financial structures that are unlike those found in most other industries. Generic audit frameworks and standard internal audit textbooks do not address the sector-specific risks, regulatory benchmarks, and audit procedures that a power sector internal auditor needs. This Guidance Note addresses that gap.

The Three Editions

First Edition—May 2015: Published by the Professional Development Committee of ICMAI. Provided a foundation framework covering the audit of Generation, Transmission, Distribution, and Trading of Power. Established the basic structure for power sector internal audit guidance in India.

Second Edition—May 2021: Published by the IAASB of ICMAI. Expanded scope with updated regulatory references applicable at that time. Covered key aspects of GENCO, TRANSCO, and DISCOM audit with reference to the then current regulatory framework.

Third Edition—2026 (This Edition): A comprehensive update building upon the earlier editions, incorporating major developments since the Second Edition and extending coverage to emerging areas of relevance. Content from earlier editions that remains relevant has been retained and updated where necessary, while new and expanded guidance has been incorporated to reflect the evolving regulatory, technological and operational landscape of the power sector.

What Is New in This Third Edition

The Third Edition incorporates the following major developments that occurred after the Second Edition:

Legislative and Regulatory:

- ✓ Electricity (Amendment) Rules, 2023 — amendments relating to captive generating plants, including captive-user/affiliate-company arrangements and recognition of specified consumption through Energy Storage Systems; consequential amendments to Rule 19 relating to renewable-energy tariff determination.
- ✓ CERC Tariff Regulations 2024-29 — new KPI norms for PAF; SHR; APC; SOC; O&M; FGD; Return on Equity
- ✓ CERC RE Tariff Regulations 2024-27
- ✓ CERC (Connectivity and General Network Access to ISTS) Regulations 2022 — replacement of LTA/MTOA framework by General Network Access
- ✓ CERC (Power Market) Regulations 2021
- ✓ CERC (Terms and Conditions for Purchase and Sale of Carbon Credit Certificates) Regulations 2026
- ✓ Ministry of Power Order on Renewable Purchase Obligation and Energy Storage Obligation — 22 July 2022

- ✓ Carbon Credit Trading Scheme 2023 — notified by Ministry of Power under Section 14AA of the Energy Conservation (Amendment) Act 2022
- ✓ Income Tax Act 2025 — effective 1 April 2026; new section references; new TDS payment codes; new form numbers; dual reference framework
- ✓ Digital Personal Data Protection Act 2023 and DPDP Rules, 2025
- ✓ Dam Safety Act 2021
- ✓ Energy Conservation (Amendment) Act 2022
- ✓ Van (Sanrakshan Evam Samvardhan) Adhiniyam 1980
- ✓ Four Labour Codes — in force from 21 November 2025; implementation to be read with the applicable Central and State rules and transitional provisions

Government Schemes and Policies:

- ✓ Revamped Distribution Sector Scheme (RDSS) 2021
- ✓ CEA Cyber Security Guidelines for Power Sector — 2021
- ✓ National Green Hydrogen Mission 2023
- ✓ MoP Guidelines to Promote Development of Pump Storage Projects 2023
- ✓ PM Surya Ghar Muft Bijli Yojana 2024
- ✓ Section 37(2)(g) — MSME 45-Day Payment Disallowance (Finance Act 2023 amendment)

New Audit Areas Introduced:

- ✓ Integrated Coal Mine Operations — captive mine GENCOs; MDO contract audit; mining statutory payments; DGMS safety compliance; mine closure provisioning
- ✓ Battery Energy Storage Systems (BESS) — RTE monitoring; ESO compliance; degradation audit
- ✓ Renewable Energy — expanded coverage of solar; wind; hydro; PSP; REC; deemed generation
- ✓ Energy Exchange and Carbon Market — CCTS; REC; ESCert; DAM; RTM; G-DAM; HP-DAM
- ✓ ESG and Sustainability — GHG emissions audit; BRSR accuracy; PAT scheme; ISSA 5000 readiness
- ✓ Cybersecurity and OT Security — CEA Cyber Security Guidelines 2021; CERT-In Directions 2022; IEC 62443; IT-OT segmentation; smart meter HES security; AI governance
- ✓ Special Entity Configurations — eight distinct configurations including 51% captive rule; Section 63/UMPP; merchant power plant; hybrid RE plus storage
- ✓ Crisis and Emergency Audit — plant accidents; grid disturbances; cyber attacks; force majeure
- ✓ Multi-Audit Universe Management — the framework for managing simultaneous CAG; CERC/SERC; income tax; GST; environmental and other regulatory audit bodies
- ✓ Common Findings and Institutional Learning — patterns from CAG; CERC/SERC; and internal audit experience across the sector

Standards Alignment:

- ✓ Global Internal Audit Standards™ (2024 Edition) — five domains; integrated throughout
- ✓ ICMAI Sustainability Standards ISS1 and ISS2 — integrated in Chapter 14 (Section 14.9)
- ✓ Forthcoming standards — ISSA 5000; ISA 240 Revised — noted for awareness

HOW TO USE THIS GUIDANCE NOTE

Who Should Use This Guidance Note

This Guidance Note is intended for:

- ✓ **CMAs appointed as internal auditors** of power sector entities under Section 138 of the Companies Act 2013
- ✓ **Chief Internal Auditors and internal audit teams** of GENCOs; TRANSCOs; DISCOMs; LDCs; and energy exchanges, whether in-house or outsourced
- ✓ **Concurrent auditors** appointed for specific areas or transaction types in power sector entities
- ✓ **Audit Committee members** of power sector entities who wish to understand the scope and framework of internal audit in the sector
- ✓ **Cost Auditors and Statutory Auditors** of power sector entities who coordinate with internal audit
- ✓ **CMA students and members** preparing for or transitioning into power sector internal audit

How This Guidance Note Is Organised

The Guidance Note is organised in a deliberate sequence from foundation to execution:

Chapters	What They Cover	Read When
1 and 2	Standards; Independence; Methodology; Reporting Framework; CAG Audit Pattern	Before any power sector audit assignment
3	Glossary — 100+ power sector terms	Whenever you encounter an unfamiliar term
4	Power sector overview — structure; schemes; technology; tariff; expert reports	Before your first assignment; refresh as sector evolves
5	Complete legal and regulatory matrix	When verifying compliance for any area or entity
6	Entity overview — GENCOs; TRANSCOs; DISCOMs; LDCs; Exchanges	To understand the entity you are about to audit
7	Special entity configurations — 8 types	When the entity has a non-standard structure
8 to 12	Entity-specific audit — Thermal GENCO; Mine; RE GENCO; TRANSCO/LDC; DISCOM	Based on the entity you are auditing
13	Energy exchange and carbon market audit	When the entity trades on exchanges or is covered by CCTS
14	Finance, procurement and contracts, taxation and cost, IT and cybersecurity, ESG and sustainability	For any entity — functional areas apply across the board
Appendices 1-15	Reference tables; checklists; formats; registers	During execution of specific audit areas

Quick Navigation by Entity Type

If you are auditing...	Start with	Primary chapter	Supporting chapters
Thermal Power Plant (GENCO)	Ch.1–4 (foundation)	Ch.8 (Thermal GENCO audit)	Ch.5 (legal); Ch.14
GENCO with Captive Coal Mine	Section 7.2 (configuration)	Ch.8 + Ch.9 (Mine audit)	Section 5.6 (mining laws); Ch.14 (cost audit)
Renewable Energy GENCO	Ch.7 (configuration)	Ch.10 (RE audit)	Section 5.2.2 (CERC RE norms); Ch.14 (ESG)
Transmission Company	Section 6.2 (entity overview)	Ch.11 (TRANSCO/LDC audit)	Section 5.2.1 (CERC tariff)
NLDC/RLDC/SLDC	Section 6.3 (entity overview)	Section 11.6 (LDC audit)	Section 5.1.5 (grid code); Ch.14 (SCADA)
Distribution Company	Section 6.4 (entity overview)	Ch.12 (DISCOM audit)	Section 5.3 (SERC); Section 12.5 (RDSS)
Energy Exchange Participant	Section 6.5 (entity overview)	Ch.13 (exchange audit)	Section 5.2.6 (market regulations)
Special Configuration Entity	Ch.7 (all configurations)	Relevant entity chapter	Section 7.10 (decision matrix)
Any entity — Tax, compliance	Section 5.9 (direct tax)	Ch.14 (tax audit)	Appendix 3 (Income Tax Act 2025 transition)
Any entity — GST compliance	Section 5.10 (GST)	Ch.14 (GST audit)	Appendix 4 (GST transaction matrix)
Any entity — IT/Cyber	Section 5.14 (cyber laws)	Ch.14 (IT/Cyber audit)	Appendix 7 (CEA Cyber Security Guidelines 2021 checklist)
Any entity — ESG/BRSR	Ch.14 (BRSR)	Ch.14 (ESG audit)	Appendix 2 (environmental standards)
Managing CAG audit	Section 2.13.10 (CAG framework)	Ch.14 (multi-audit)	Appendix 14 (Master Findings Register)
Managing CERC/SERC prudency	Section 2.13 (reporting framework)	Ch.14 (CERC/SERC interface)	Relevant entity chapter pre-petition sections

How to Use Specific Sections

The Glossary (Chapter 3): Do not read from beginning to end. Use it as a quick reference whenever you encounter a term in a regulation, management report, or tariff order that you are not fully certain about. The glossary is organised in thematic groups such as regulatory; generation; transmission; distribution; coal/mining; RE; exchange/carbon; ESG; IT; financial etc. so you can navigate to the right group quickly.

The Legal Matrix (Chapter 5): Use it as a checklist when planning compliance audit for any area. When auditing fuel management, go to Section 5.6 (coal/mining laws) and Section 5.13 (transport laws). When auditing environmental compliance, go to Section 5.7. When auditing tax compliance,

go to Sections 5.9 and 5.10. The chapter does not need to be read end-to-end; navigate to the relevant section for the area being audited.

The Entity Chapters (Chapters 8–13): Each entity chapter begins with a Red Flag Dashboard of 10 indicators. Start there. The Red Flag Dashboard tells you where to focus first based on what is most likely to be wrong. Then follow the structured sections in sequence.

The Appendices: These are working tools, not background reading. Appendix 1 gives you the CERC 2024-29 norms you need during plant KPI audit. Appendix 3 gives you the Income Tax Act 2025 transition table you need during tax audit. Appendix 14 gives you the Master Audit Findings Register format you need to track multi-audit findings. Use the appendices during execution, not during planning.

Section 4.5.1 (Forward-Looking — Draft Legislations): Read this once at the beginning of each audit cycle. It lists draft legislations and proposed regulations that are not yet in force but are likely to affect power sector audit in the near future. Add any that have been notified since the date of this publication to your compliance checklist for the relevant entity.

What This Guidance Note Is and Is Not

What it is:

- ✓ A practical execution guide for power sector internal audit
- ✓ A sector-specific reference that supplements, not replaces the ICMAI IAAS and Global Internal Audit Standards™ (2024 Edition)
- ✓ A self-contained reference that covers pre-2021 and post-2021 content
- ✓ A living document to be supplemented with state-specific regulations for the entity being audited and with new developments as they occur

What it is not:

- ✓ A substitute for ICMAI IAAS or Global Internal Audit Standards™ (2024 Edition) for generic audit methodology — those standards are the primary reference
- ✓ A legal opinion — auditors must exercise independent professional judgment and, where legal interpretation is required, seek appropriate legal advice
- ✓ A guarantee of regulatory compliance — regulations evolve; auditors must verify the current position on specific regulatory matters before relying on this Guidance Note for any particular engagement
- ✓ An exhaustive state-by-state regulatory reference — state-specific SERC tariff orders; state grid codes; state RPO trajectories; state pollution control board consents; and state labour notifications must be obtained and reviewed separately for the entity being audited

1. INTERNAL AUDIT — PURPOSE, STANDARDS AND FRAMEWORK

1.0 Introduction

India's power sector covers generation, transmission, load despatch, distribution and trading. It operates under the Electricity Act 2003 and the oversight of CERC, SERCs, CEA and other statutory bodies, with significant environmental, labour, taxation and corporate governance obligations (structure and scale: Chapter 4). A single generating company may buy coal worth thousands of crores a year, and a distribution company may spend tens of thousands of crores on power purchase. In this setting, internal audit gives the Board, Audit Committee, regulators and other stakeholders assurance that resources are used prudently, regulations are complied with, operations are managed effectively and financial reporting is reliable.

1.1 Objectives of This Guidance Note

a) To provide a single, practical reference for CMAs and other professionals auditing power sector entities, from coal mine to energy exchange: GENCOs (including integrated coal mines), TRANSCOs, DISCOMs, Load Despatch Centres and energy exchanges. It equips them to identify fraud risk, quantify financial impact, evaluate regulatory compliance, assess operational performance and report to the Audit Committee and Board.

b) To update the Second Edition (May 2021) for the legislative, regulatory and policy changes since then (see About This Guidance Note).

c) To align with ICMAI IAAS, ICMAI Sustainability Standards ISS1 and ISS2, and the Global Internal Audit Standards™ (2024 Edition) (see Section 1.3).

d) To guide internal auditors in managing the multi-audit environment, in which CAG, CERC/SERC, tax, GST and environmental authorities examine the entity at the same time as internal audit.

e) To provide audit frameworks for areas that have become material since the Second Edition.

1.2 Scope

1.2.1 What This Guidance Note Covers

Primary entities — whose operations are covered:

- ✓ Generation Companies (GENCOs) — thermal, hydro, solar, wind, battery energy storage, and green hydrogen; including Integrated Coal Mine operations where GENCOs operate captive coal mines
- ✓ Transmission Companies — Central PSUs like PGCIL and State Transmission Utilities (STUs)
- ✓ National, Regional and State Load Despatch Centres (NLDC/RLDC/SLDC)
- ✓ Distribution Companies (DISCOMs) — state utilities, private licensees, and franchisees
- ✓ Power traders and energy exchanges — to the extent of compliance and market operations audit

Reference entities: The ministries, regulators, appellate and standard-setting bodies listed in Section 4.3.2 are not themselves audit subjects under this Guidance Note. Their orders, norms and standards form the benchmarks against which the primary entities are audited.

The Guidance Note also covers functional audit areas common to all entities. These include procurement and contracts, capital works, stores, treasury, HR, taxation, IT and cybersecurity, ESG and statutory compliance (Chapter 14).

1.2.2 What This Guidance Note Does Not Cover

- ✓ Nuclear Power Plants in detail — brief reference points in Chapter 10
- ✓ Offshore wind power — the proposed regulatory framework is noted in Section 4.5.1; a detailed audit framework will follow in a future edition
- ✓ Green hydrogen in detail — key audit points in Chapter 10
- ✓ Audit of regulatory bodies — CERC, SERCs, CEA, APTEL are subject to CAG audit and separate government audit frameworks
- ✓ Audit of electricity consumers — consumers are relevant to DISCOM audit in Chapter 12 but are not themselves audit subjects
- ✓ State-specific regulations in exhaustive detail — auditors must supplement this Guidance Note with applicable SERC tariff orders, state grid codes, state RPO trajectories, and state environmental regulations etc.

1.3 Applicable Professional Standards

1.3.1 ICMAI Internal Audit and Assurance Standards (IAAS)

The IAASB of ICMAI has issued IAAS covering performance, operational, forensic, system and transaction audit. Internal auditors using this Guidance Note must conduct their work in conformance with applicable ICMAI IAAS. ICMAI's Sustainability Standards ISS1 (General Requirements for Sustainability Disclosure) and ISS2 (Climate Risk Disclosures) apply to the ESG audit framework in Chapter 14.

1.3.2 Global Internal Audit Standards™ (2024 Edition)

The IIA issued the Global Internal Audit Standards in January 2024, effective from January 2025, replacing the standards in the 2017 International Professional Practices Framework (IPPF). The Standards are organised in five domains: Purpose of Internal Auditing; Ethics and Professionalism; Governing the Internal Audit Function; Managing the Internal Audit Function; and Performing Internal Audit Services. Power sector internal auditors are encouraged to align their practice with them. Their key implications are integrated throughout this Guidance Note, particularly in risk-based internal audit (Section 2.3), the Audit Committee relationship (Section 2.12) and quality assurance (Section 2.14).

1.3.3 Professional Scepticism

Both ICMAI IAAS and Global Internal Audit Standards™ (2024 Edition) place increased emphasis on professional scepticism. In the power sector context, this means: do not accept management explanations at face value, verify with independent evidence; do not assume that what was true last year is true this year; do not treat a paper trail as proof of reality, physical verification is as important as document verification; and do not allow familiarity with the entity to reduce alertness. Dedicated sections on Paper Audit vs. Reality Audit (Section 2.7) and Management Explanations vs. Audit Reality (Section 2.8) are provided in Chapter 2.

1.3.4 Forthcoming Standards — Awareness

ISSA 5000, General Requirements for Sustainability Assurance Engagements, issued by the International Auditing and Assurance Standards Board of the International Federation of Accountants (IFAC), applies to assurance on sustainability information for periods beginning on or after 15 December 2026. It is relevant to listed power entities whose BRSR Core is subject to reasonable assurance under SEBI requirements (Section 14.9). ISA 240 (Revised), on the auditor's responsibilities relating to fraud, takes effect for periods beginning on or after 15 December 2026, and the fraud risk frameworks in this Guidance Note take account of its strengthened requirements. Auditors should check the ICMAI website for IAAS issued or amended after this publication.

1.4 Referral Documents

The laws, CERC/CEA regulations and policies the internal auditor should keep at hand are listed with their audit implications in Chapter 5 and Appendix 8, and the government schemes in Appendix 9. Draft regulations listed in Section 4.5.1 should be added to this list as and when they are notified, and state-specific instruments must be obtained separately (see Section 1.2.2). In addition, the following professional references apply:

- ✓ ICMAI Internal Audit and Assurance Standards (IAAS) — latest edition
- ✓ ICMAI Sustainability Standards ISS1 and ISS2
- ✓ Global Internal Audit Standards™ (2024 Edition)
- ✓ GHG Protocol Corporate Standard
- ✓ CO_2 Baseline Database for Indian Power Sector (updated annually)
- ✓ BEE PAT Scheme Regulations and M&V Guidelines

1.5 Independence, Ethics and Professional Conduct

1.5.1 Independence

Independence is the cornerstone of effective internal audit. In the power sector, where entities are often large PSUs with complex hierarchies and significant political oversight, independence faces unique challenges. The internal auditor must maintain objectivity; avoid conflicts of interest; and not be influenced by the seniority of the person against whom an adverse finding is being raised.

Specific considerations for the power sector: an in-house internal auditor must not audit an area in which they previously worked, and the Chief Internal Auditor must have direct access to the Audit Committee without management filtering. Rotation requirements, which depend on how the function is structured, are set out in Section 1.6.

1.5.2 Ethics and Professional Conduct

The ICMAI Code of Ethics governs professional conduct. In the power sector, auditors in fuel audit areas must be alert to approaches from coal suppliers; contractors whose bills are under audit sometimes approach auditors informally; and management may seek the internal auditor's concurrence on tariff petition data that does not accurately reflect actual performance. In all such situations, the internal auditor must decline to participate, document the situation, and report it to the Chief Internal Auditor or directly to the Audit Committee.

1.5.3 What To Do When Under Pressure

When management asks for a finding to be modified or dropped, ask for the request in writing with specific factual reasons; most verbal pressure recedes once written confirmation is sought. Never

modify a factually correct finding merely because management is displeased, and record every interaction: the date, the person, what was said and your response. If you face a threat of transfer or an adverse appraisal, keep a contemporaneous record and bring it directly to the Audit Committee at once; if the threat is carried out, it constitutes interference with internal audit independence and must be reported as such. Where senior management is implicated in a finding, secure the documentation and working papers first and then report directly to the Audit Committee, bypassing all levels of executive management. When uncertain whether to proceed, ask whether your conduct would withstand professional scrutiny; when in doubt, document, and do not suppress.

1.6 Internal Audit Function — Common Framework with Exceptions

The structure of the internal audit function varies across power sector entities. The substantive audit content of this Guidance Note is identical regardless of structure. However, certain aspects differ and these exceptions are noted below.

Scope: Where the internal auditor is appointed for a limited scope, the relevant chapters applicable to the assigned scope should be followed. The appointment letter or Terms of Reference must clearly define the scope.

Independence and rotation: In-house employees rotate across audit areas at least every three years, to prevent familiarity threat. A single outsourced firm should have no other commercial engagement with the entity and should be rotated every five years. Where several auditors or firms are appointed by plant or unit, they are also rotated across plants within the engagement period, at a frequency set by the Chief Internal Auditor or Audit Committee. Where an in-house team and an outsourced firm work together, their areas are clearly defined with no overlap and are coordinated through the Chief Internal Auditor.

Reporting: Regardless of structure, material findings must reach the Audit Committee. An outsourced firm must have the same right of direct access to the Audit Committee as an in-house Chief Internal Auditor.

Coordination with other audit bodies: The responsibility for coordinating with CAG, CERC/SERC, income tax, GST, and other regulatory audit bodies, as detailed in Chapter 14, rests with whoever is the designated internal audit function. This cannot be abdicated regardless of structure.

1.7 Internal Audit Charter

Every internal audit function in a power sector entity should operate under a formal Internal Audit Charter, approved by the Board on the recommendation of the Audit Committee and reviewed at least once every three years. At a minimum, the Charter should cover: purpose and mission; scope; independence and objectivity; authority to access records, personnel and premises without restriction; the administrative and functional reporting lines; direct access to the Audit Committee; coordination with CAG, the Statutory Auditor, the Cost Auditor and Vigilance; the applicable standards (ICMAI IAAS and the Global Internal Audit Standards™ (2024 Edition)); quality assurance requirements; the Annual Audit Plan approval process; and resources and budget.

A model Internal Audit Charter for power sector entities is provided in Appendix 13.

1.8 Coordination Framework

With Statutory Auditor: Share the annual internal audit plan at the beginning of the year; provide internal audit reports on request, particularly findings on internal controls; do not rely on statutory audit work for areas requiring independent internal audit coverage.

With Cost Auditor: Share cost centre-wise findings with implications for cost records; internal audit findings on SHR, APC, fuel consumption, and O&M costs are relevant inputs for cost audit. Refer Chapter 14 for the multi-audit learning loop.

With CAG Audit: Facilitate CAG audit parties professionally. Internal audit does not substitute for CAG audit, because the two have different mandates. The CAG reporting process, pre-emptive review of areas CAG has audited, and tracking of CAG paras in the Master Audit Findings Register are covered in Sections 2.13.10, 2.13.11 and 14.10.

With Vigilance Department (for PSUs): Internal audit and vigilance are distinct functions: internal audit provides systemic assurance whereas vigilance investigates individual wrongdoing. When internal audit uncovers potential fraud, refer the matter to vigilance with proper documentation and do not investigate criminal wrongdoing independently. Coordinate at the beginning of each year to avoid duplication of audit coverage.

Fraud Prevention Policy reporting: Each quarter, internal audit reports to the Audit Committee on every fraud incident detected or reported. The report covers its nature and estimated amount, the unit involved, management's corrective action, and the status of any disciplinary or legal proceedings. Cases are carried forward until resolved. Dropping unresolved matters from later reports is itself a control weakness. As part of the annual audit plan review, internal audit also assesses the adequacy of the Fraud Prevention Policy: whistle-blower access, fraud awareness training for high-risk roles, and alignment with emerging fraud patterns in CVC advisories and CAG findings.

2. OVERVIEW OF INTERNAL AUDIT METHODOLOGY

2.0 Introduction and Definition of Internal Audit

2.0.1 Definition of Internal Audit

Internal audit is defined under ICMAI IAAS as: *"An independent, objective assurance and consulting activity designed to add value and improve an organisation's operations. It helps an organisation accomplish its objectives by bringing a systematic, disciplined approach to evaluate and improve the effectiveness of risk management, control, and governance processes."*

The Global Internal Audit Standards™ (2024 Edition), under Domain I – Purpose of Internal Auditing, state: *"Internal auditing strengthens the organization's ability to create, protect, and sustain value by providing the board and management with independent, risk-based, and objective assurance, advice, insight, and foresight."*

Both frameworks emphasize three essential elements: independence and objectivity; a systematic and disciplined approach; and adding value. In the power sector, value may be added by preventing a CERC disallowance, detecting coal weighment fraud before it becomes material, identifying a regulatory non-compliance before it attracts a penalty, or improving the accuracy of AT&C loss reporting.

2.0.2 Statutory Basis and Governance Framework

Section 138 of the Companies Act 2013 requires specified classes of companies to appoint an internal auditor, who may be a Cost Accountant. Most power sector entities fall within the mandatory scope. In addition, the following governance frameworks require or rely on a functioning internal audit:

- ✓ **SEBI LODR Regulations 2015** — for listed power companies; mandate Audit Committee oversight of internal audit function
- ✓ **DPE Guidelines on Corporate Governance for CPSEs** — mandatory for Central PSUs including NTPC, NHPC, PGCIL etc.
- ✓ **CVC Guidelines on Vigilance and Internal Audit** — applicable to all government-owned entities; define minimum internal audit coverage requirements
- ✓ **CAG Auditing Standards** — useful reference benchmarks for internal auditors of government-owned power entities
- ✓ **DPE Guidelines on Investment of Surplus Funds** — govern investment of surplus funds by Central PSUs; prescribe eligible instruments, minimum credit ratings and issuer concentration limits. Investments of employee benefit trusts are governed separately: exempted Provident Fund trusts follow the pattern of investment notified by the Ministry of Labour and Employment, and approved gratuity and superannuation funds follow the Income-tax Rules. Internal audit verifies compliance with both.
- ✓ **MCA Cost Audit Rules and CARO 2020** — the statutory auditor must report under CARO 2020 whether the company has an internal audit system commensurate with its size and business and whether internal audit reports were considered, and the cost auditor relies on the cost records that internal audit tests; both make the quality of internal audit visible to external auditors
- ✓ **Ind AS 115 (Revenue from Contracts with Customers) and Ind AS 114 (Regulatory Deferral Account Balances) —** revenue recognition policies, particularly for DISCOMs

recognising regulatory assets and entities reporting unbilled revenue, are high-risk areas that internal audit should verify every year.

Further, CERC and SERC tariff regulations and filing requirements may require specified financial, operational, fuel-related, capital-expenditure and other data submitted in tariff petitions to be supported by audited accounts or certificates from the statutory auditor or other prescribed professional, as applicable. Internal audit, while not a substitute for such prescribed certification, plays an important role in strengthening the accuracy, reliability, control environment and audit-readiness of data used in regulatory submissions.

The Ministry of Corporate Affairs is considering amendments to the Companies Act 2013 to further strengthen internal audit provisions. Refer Section 4.5.1.

2.0.3 Role of CMA in Power Sector Internal Audit

CMAs are well positioned to conduct internal audit in power sector entities. Section 138 of the Companies Act 2013 expressly names a cost accountant as eligible for appointment as internal auditor, and the profession's expertise in cost accounting, performance measurement and regulatory compliance matches the needs of entities where cost efficiency, operational performance and tariff compliance are central concerns.

2.1 Internal Audit Objectives in Power Sector

a) To evaluate the adequacy and effectiveness of internal controls across financial, operational, regulatory, and compliance functions.

b) To verify that operations are conducted in accordance with applicable laws, regulations, tariff orders, and management policies including those issued by CERC, SERCs, CEA, MoEFCC, DGMS, and other regulatory bodies.

c) To assess whether operational performance measured through KPIs such as Plant Availability Factor (PAF), Station Heat Rate (SHR), Auxiliary Power Consumption (APC), AT&C losses, and other sector-specific parameters is being monitored, reported accurately, and managed effectively.

d) To identify areas of financial leakage, revenue loss, excess expenditure, or under-recovery and quantify the financial impact of control weaknesses.

e) To evaluate the risk management framework, whether significant risks are identified, assessed, and mitigated to an acceptable level.

f) To detect and deter fraud, irregularities, and misappropriation through risk-based audit procedures and specific fraud-focused examination.

g) To provide assurance on the accuracy of data submitted to regulatory bodies including tariff petitions to CERC/SERC, generation data to CEA, environmental compliance reports to MoEFCC/SPCB, and energy data to NLDC/RLDC/SLDC.

h) To evaluate the adequacy of ESG and sustainability-related disclosures and reliability of underlying data, particularly for entities subject to mandatory BRSR reporting.

i) To assist the Audit Committee and Board in discharging their governance responsibilities by providing timely, relevant, and actionable audit findings and recommendations.

j) To support the entity in managing the multi-audit environment including coordinating with CAG, statutory auditors, cost auditors, regulatory audit bodies, and other oversight agencies as detailed in Chapter 14.

2.2 Scope of Internal Audit

The scope encompasses: Operational Audit (Chapters 8–13); Regulatory Compliance Audit (Chapters 5 and 8–14); Financial Audit, Performance Audit, IT and Cybersecurity Audit, ESG and Sustainability Audit (Chapter 14); Fraud Risk Assessment (within each entity chapter); Propriety Audit — whether expenditure is not merely legal but also prudent and in public interest, particularly relevant for government-owned power PSUs; and Follow-up Audit (Section 2.11). The precise scope for any entity is defined in the Annual Audit Plan based on risk assessment. For detailed guidance on audit types applicable in general, refer ICMAI IAAS.

2.3 Risk-Based Internal Audit (RBIA)

2.3.1 Concept

Risk-Based Internal Audit directs internal audit resources towards areas of highest risk. This is aligned with ICMAI IAAS and Global Internal Audit Standards™ (2024 Edition). In the power sector, RBIA is particularly important given: the large number of auditable units; wide range of risk types like operational, regulatory, financial, environmental, cyber, and fraud; significant financial stakes in individual audit areas; and limited internal audit resources relative to the scale of operations.

2.3.2 Risk Universe — Power Sector Entities

The audit universe of each entity type is set out below. Table A shows auditable areas common to two or more entity types. Table B shows areas specific to one entity type. Both tables use the risk categories applied in the risk assessment matrix (Section 2.3.3).

Risk categories: F = Financial; Fr = Fraud; O = Operational; R = Regulatory; L = Legal; C = Compliance; Cy = Cyber; Rp = Reputational; S = Safety. A dash (—) means the area is not a key risk area for that entity type. It is still covered at normal risk.

Table A — Common Auditable Areas

Auditable area	Thermal GENCO	RE GENCO	TRANSCO	LDC	DISCOM
Procurement and contracts, including O&M contracts	F, Fr	F (O&M with OEM)	F, Fr (O&M contracts)	—	F, Fr
Capital works and project execution	F, Fr	—	F, Fr (new lines; substations)	—	—
HR and payroll	F, C	—	F, C	—	F, C

GST and direct tax compliance	F, R	—	—	—	F, R
IT, OT and SCADA security	Cy, O (IT and OT/SCADA)	—	Cy, O (OT/SCADA)	Cy, O (SCADA/EMS)	Cy, O (billing; smart meter HES)
Environmental and forest compliance	R, L (FGD; CEMS; ash)	R, L (environmental and forest clearance)	R, L (RoW; green belt)	—	—
ESG, sustainability and carbon	R, Rp (ESG reporting)	R, F (ESG and carbon credit obligations)	—	—	—
Tariff filings and tariff billing	R, F (tariff petition data; regulatory filings)	—	F, R (transmission tariff billing and recovery)	—	—

Table B — Entity-Specific Auditable Areas

Entity	Specific auditable areas (risk category)
Thermal GENCO	Coal procurement and fuel management (F, Fr); plant operations — SHR, APC, PAF (O, R); treasury and banking (F); integrated mine operations, where applicable (O, R, S)
RE GENCO	Generation performance — CUF, PR (O, F); REC registration and trading (F, R); RPO compliance certificate (R); PPA terms compliance (F, R); BESS performance — RTE, degradation (O, F); project finance covenants — DSRA, DSCR (F, R)
TRANSCO	ISTS charges under the CERC Sharing Regulations 2020 (F, R); transmission losses — normative vs actual (F, R); GNA connectivity compliance (R); SCED implementation (O, R)
Load Despatch Centre	Scheduling accuracy — day-ahead and real-time (O, R); DSM charge computation and settlement (F, R); system operation charges — approval and recovery (F); ancillary services management (O, R); REC registry operations, NLDC (F, R); cross-border trading accounting (F, R); grid incident documentation (R, L)
DISCOM	Revenue — billing, collection, AT&C losses (F, Fr); power purchase — prudency, RPO compliance (F, R); regulatory asset accounting and recovery (F, R); RDSS implementation — smart meters, grants (F, R); consumer services — CGRF, Ombudsman (R, Rp); subsidies — DBT, state government reimbursement (F, C)

2.3.3 Risk Assessment Matrix

Likelihood / Impact	High Impact	Medium Impact	Low Impact
High Likelihood	Critical	High	Medium
Medium Likelihood	High	Medium	Low
Low Likelihood	Medium	Low	Low

Areas rated Critical or High receive priority coverage in the Annual Audit Plan. Areas rated Medium are covered on a rotational basis. Areas rated Low may be covered through limited procedures or analytical review.

2.3.4 Annual Audit Plan

The Annual Audit Plan is prepared by the Chief Internal Auditor based on the risk assessment of the audit universe. It specifies: auditable areas and basis for selection; estimated audit time; quarter-wise scheduling; team composition; and areas deferred with rationale. The Plan must be presented to and approved by the Audit Committee before the audit year commences. For entities with multiple plants or circles, a rolling three-year coverage approach is recommended so that every significant auditable area is covered at least once in three years, with higher-risk areas covered annually.

2.3.5 Internal Control Framework and Risk and Control Matrix

The Internal Control Framework (ICF) is how an entity identifies its key risks, documents the controls that mitigate them, assigns each control to an owner and monitors them. Power sector entities answer to several regulators, hold assets of significant public value and are subject to CAG oversight. For them the ICF is not optional: it is the foundation of the risk-based audit plan, and its adequacy determines the quality of assurance internal audit can give.

Framework Structure — The ICF follows three lines of defence:

- ✓ **First line:** process owners and operational management, such as the plant manager and procurement head. They own the risks and design and operate the controls.
- ✓ **Second line:** risk management, compliance and finance. They set control standards, monitor performance and report exceptions.
- ✓ **Third line:** internal audit, which gives the Audit Committee and Board independent assurance that the first two lines work as designed.

The Risk and Control Matrix (RCM) makes the ICF operational. For each significant process (fuel procurement, capital expenditure, revenue billing, treasury, HR and payroll, regulatory compliance) it records the process objective; key risks; inherent risk rating; key controls, preventive or detective; control owner; frequency and evidence of operation; residual risk rating; and internal audit testing frequency.

Illustrative RCM Structure — Fuel Procurement Process

Risk	Inherent Rating	Key Control	Control Type	Control Owner	Audit Frequency
Coal received at grade below FSA contracted grade — GCV shortfall not detected or disputed	High	Third-party sampling at unloading point; GCV dispute filed within 45 days of sampling report	Detective / Preventive	Chief of Fuel Management	Quarterly
ACQ shortfall by coal company — penalty not raised	High	Monthly ACQ tracking register; penalty bill raised within 30 days of shortfall confirmation	Detective	Fuel Management Officer	Quarterly

Coal stock physical vs book variance beyond the normal 2–3% range — pilferage not detected	High	Monthly theoretical stock computation; surprise drone/GPS volumetric survey	Detective	Plant Store In-charge	Half-yearly
Payment to coal supplier above invoice quantity — over-payment	Medium	Three-way match — PO, weighment slip, invoice — before payment release	Preventive	Finance Controller	Continuous
Unauthorised advance to supplier beyond DFP limit	Medium	System-level approval workflow; advance register reviewed monthly	Preventive	CFO / DFP authority	Quarterly

How internal audit uses the RCM: The RCM is the primary input to the Annual Audit Plan, and each control's testing frequency follows its residual risk. Management designs the RCM; internal audit validates it, checking whether the risks are complete, whether the documented controls actually operate, and whether their design brings risk down to the accepted level. Any gap between the documented control and actual practice is itself a finding, for example a "daily" control that runs monthly, or an evidence register not updated for three months. The RCM is updated annually before the audit plan is finalised. It is also updated during the year after any significant process change, regulatory development or new risk, such as the Income Tax Act 2025 TDS codes, the CERC Tariff Regulations 2024-29 or a new ERP.

2.4 Types of Audit, Sampling, and Documentation — Power Sector Application

Internal audit in the power sector encompasses financial, compliance, operational, performance, forensic, IT, ESG, concurrent, and propriety audit. In practice, most power sector assignments combine compliance, operational, and financial audit simultaneously for a given area or process. For detailed guidance on each type, sampling methodology, and documentation standards, refer ICMAI IAAS and Global Internal Audit Standards™ (2024 Edition). Power sector-specific application of these concepts is embedded within the relevant entity chapters.

Four power sector-specific aspects are set out below: financial and non-financial materiality, the seasonal audit calendar, and special audit.

2.4.1 Financial Materiality

Financial materiality thresholds — indicative:

Entity Type	**Indicative Financial Materiality per Finding**
GENCO (above 2000 MW)	Rs. 50 lakhs
GENCO (500 to 2000 MW)	Rs. 25 lakhs
DISCOM (above 10 lakh consumers)	Rs. 50 lakhs
DISCOM (2 to 10 lakh consumers)	Rs. 25 lakhs
TRANSCO	Rs. 50 lakhs
Integrated Mine	Rs. 25 lakhs

For smaller entities, the Audit Committee fixes the threshold on the recommendation of the Chief Internal Auditor.

2.4.2 Non-Financial Materiality

Certain findings are material regardless of financial value like any violation of environmental regulations that could lead to plant shutdown; any cybersecurity vulnerability in SCADA or OT systems affecting grid security; any safety violation in plant or mine operations creating risk to human life; any manipulation of data submitted to CERC/SERC or CAG; and any finding involving the conduct of senior management. Non-financial material findings must be reported to the Audit Committee irrespective of financial quantum.

2.4.3 Seasonal Audit Calendar

Quarter	Season	Operational Characteristic	Recommended Audit Focus
April - June	Summer	Peak demand; high exchange prices; grid stress	Power purchase audit — emergency procurement justification; exchange price prudency; grid code compliance during peak
July - September	Monsoon	Hydro generation peaks; coal transportation disrupted; coal stock critical	Coal stock audit; coal receipt quality; hydro reservoir operations; capital works progress
October - December	Post-monsoon	Coal stacking season; capital works completion; pre-year-end	Coal stock physical verification; capital works completion and capitalisation; year-end provisions; environmental compliance
January - March	Year-end	Tariff petition preparation; regulatory filings; financial statement closing	Pre-petition data audit; provisions adequacy; statutory compliance calendar; CERC/SERC filing data verification

2.4.4 Special Audit

A Special Audit is a focused, time-bound internal audit commissioned outside the Annual Audit Plan in response to a specific trigger. Unlike routine audit, it is reactive, and is directed at an area, set of transactions, process or unit that has come under question. It may be triggered by: a specific and credible whistle-blower complaint within internal audit's competence; a CAG or regulatory finding that reveals a systemic weakness needing immediate assessment across units; a significant irregularity found in routine audit that needs examination beyond its scope; a Board or Audit Committee direction after an adverse development, such as a contract dispute, major claim settlement, unusual expenditure trend or show-cause notice; or a CVC directive. The Chief Internal Auditor commissions it in consultation with the Audit Committee Chairman; a Board direction is itself the authority.

Scope: The scope is defined for each engagement and drawn from: the adequacy of controls, and the gaps that allowed the trigger event; irregularities in transactions, records or approvals; potential fraud, misappropriation or abuse of authority, to the extent this is within internal audit's competence and does not need forensic or law-enforcement capability; compliance with policies, regulations, contracts and delegated authority; and corrective and preventive recommendations. Evidence of criminal wrongdoing is referred at once to Vigilance and, where applicable, to law enforcement, and internal audit does not investigate it further (see Section 1.8).

Conduct and Reporting: A Special Audit is carried out by a team separate from the routine audit team for that area. It works under terms of reference approved by the Audit Committee Chairman or the Board, which fix the scope, period, reporting deadline and distribution. The report goes directly to the Audit Committee and the CMD/MD, not through line management of the area. It states findings as facts supported by evidence and does not characterise intent or culpability, which rest with Vigilance or an inquiry committee. Management's action-taken response is placed before the Audit Committee within 60 days and is tracked in the Master Audit Findings Register like any other finding.

2.5 Audit Planning — Entity Understanding

Before commencing any internal audit assignment, the internal auditor should document an entity understanding as the first working paper which should be refreshed at the beginning of every audit cycle.

Entity Profile: Type of entity like GENCO/TRANSCO/DISCOM/LDC/Exchange; installed capacity / circuit km / consumer base / mine capacity as applicable; ownership type like Central PSU / State PSU / Private / JV; current financial position like profit/loss; debt level; pending regulatory assets.

Regulatory Position: Current CERC/SERC tariff order period and key parameters applicable; status of latest tariff petition like filed/pending/decided; pending CERC/SERC disallowances and appeals; RPO compliance status.

Contractual Framework: Key PPAs in force — parties; tenure; tariff structure; FSA status — ACQ; linkage; shortfall position (for thermal GENCOs); major O&M contracts — parties; tenure; value.

Multi-Audit Status: Status of last CAG audit — pending inspection report paras; pending audit report paras; status of last income tax assessment — pending demands; appeals; pending GST demands or investigations; pending environmental compliance notices or NGT orders.

Operational Status: Major capital projects underway — stage of completion; cost vs. budget; environmental compliance issues pending like FGD; CEMS; ash pond; recent operational incidents like forced outages; grid disturbances; mine accidents.

Previous Internal Audit: Last internal audit report and its significant findings and their status; open paras from previous years and their current status; repeat findings.

Expert and Due Diligence Reports: Pending expert committee recommendations — are they implemented? Lender due diligence reports — are conditions subsequent complied with? Independent Engineer reports — significant observations to follow up. Refer Section 4.14.

For multi-location entities: plan which locations are audited in the current year; larger or higher-risk locations receive more audit time; fuel management and plant KPI audit must be conducted at each plant.

2.6 Audit Evidence — Power Sector Specific Sources

For general guidance on audit evidence, refer ICMAI IAAS. The following evidence forms are particularly significant in power sector audit:

- ✓ **Physical Evidence** — coal stock physical survey; meter reading verification; plant equipment inspection; mine overburden dump stability inspection. Physical evidence is critical where paper records may not reflect ground reality — refer Section 2.7
- ✓ **Digital and System-Generated Evidence** — data extracted from ERP systems, SCADA logs, smart meter data, NLDC/RLDC scheduling data, and IEX/PXIL/HPX settlement records. The internal auditor must verify the integrity of the system before relying on its data
- ✓ **Expert Evidence** — Independent Engineer reports; actuarial valuations; IIT/NIT certificates for ash pond stability; CIMFR reports for coal GCV; expert committee reports; lender due diligence reports; insurance survey reports — refer Section 4.14. When relying on expert evidence, satisfy yourself regarding the competence and independence of the expert

Working papers for power sector entities should be retained for a minimum of **eight years** because the CERC/SERC true-up petitions may be filed several years after the relevant audit period, and CAG audit paras may remain open for extended periods.

2.7 Paper Audit vs. Reality Audit

One of the most important distinctions in power sector internal audit is between what records show and what actually exists on the ground. The internal auditor must be alert to the possibility that records, reports, and filings may not accurately reflect operational reality.

Area	What Paper May Show	What Ground Reality May Be
Coal stock	Quantity as per stock register	Lower quantity as per physical survey — difference due to measurement error or other causes
Plant outage classification	Forced outage due to grid constraint	Actual equipment failure classified as grid constraint to protect PAF computation
CEMS data	High uptime on OCEMS portal	Analyser not operational for extended periods; data entered manually
AT&C losses	Lower percentage as per SERC filing	Higher actual losses — agriculture feeder consumption estimated, not metered
Ash utilisation	100% as per Fly ash utilisation report (CPCB portal)	Ash disposed of in ways not reflected in utilisation records
Mine production	As per weighbridge records	Weighbridge records not reflecting actual dispatches accurately
Contractor work completion	100% complete as per MB	Work partially incomplete; measurement book signed prematurely

Physical verification is a mandatory component of the audit programme for all material operational areas. For every significant operational parameter, the internal auditor should wherever practicable verify from a source independent of the primary records of the entity.

2.8 Management Explanations vs. Audit Reality

Management will provide explanations for observed deviations. The internal auditor must evaluate these objectively neither accepting them at face value nor dismissing them without adequate consideration.

Management Explanation	Recommended Audit Response

Management Explanation	Recommended Audit Response
SHR is high because grid backed down generation	Obtain SLDC/RLDC backing-down instructions; cross-verify with SCADA generation logs; verify whether backing-down was complete or partial
Coal GCV was poor — hence generation was lower	Obtain third-party sampling certificates; verify who selected the sampling agency and whether the process was independent
AT&C loss is high due to unmetered agriculture consumption	Obtain feeder-wise metered data; verify the basis and vintage of the unmetered consumption estimate
Capital work was delayed due to contractor default	Verify whether performance guarantee was invoked; whether contractor was penalised per contract terms
Environmental violation was temporary and now corrected	Obtain CEMS data for the period; verify whether SPCB was notified within the prescribed timeline
CAG observation is factually incorrect	Obtain specific evidence addressing each factual element of the CAG finding; evaluate objectively
MSME payment delayed due to cash flow constraints	Section 37(2)(g) disallowance under Income Tax Act 2025 applies regardless of reason — compute and report the tax impact

Document management explanations in working papers along with their evaluation. Where accepted then record basis for acceptance. Where not accepted then retain finding with management's explanation noted alongside.

2.9 Data Analytics — Power Sector Applications and Continuous Monitoring

Analytics should cover the full population of transactions, not a sample. Start with what happened (exceptions against norms and thresholds), then why it happened (correlation with locations, personnel, periods or counterparties). Where the data allows, add predictive risk scoring to direct audit effort. For general methodology, refer to ICMAI IAAS. AI and machine-learning tools can also detect anomaly clusters that no pre-set rule would catch. This is particularly relevant to procurement and fuel management, where the manipulation patterns documented by CAG are of this kind.

Analytics Application	Area	What It Identifies
Monthly SHR trend vs. CERC norm	Thermal GENCO	Periods of abnormal heat rate; correlation with coal GCV or equipment condition
Feeder-level AT&C loss analysis	DISCOM	High-loss feeders; sudden increase in losses indicating potential fraud or metering failure
Coal GCV trend vs. FSA grade	Thermal GENCO	GCV deterioration; basis for GCV dispute claims
PAF outage classification cross-check	Thermal GENCO	Every outage classified as grid constraint cross-referenced against SLDC dispatch instructions and SCADA historian — flags forced outages mis-classified to inflate PAF
Split purchase order detection	Procurement	Orders split below approval threshold to avoid higher authority
Duplicate payment detection	Accounts payable	Same invoice paid twice; payments to same vendor on same date

Analytics Application	Area	What It Identifies
Vendor master fraud analytics	Procurement	Vendors sharing PAN, bank account number, registered address, or mobile number — indicators of shell vendor networks
MSME creditor aging analysis	Accounts payable	Balances outstanding beyond 45 days — Section 37(2)(g) exposure under Income Tax Act 2025
Smart meter tamper detection	DISCOM revenue	Meters with zero consumption; sudden consumption drop; tamper flag alerts
DSM charge anomaly detection	Scheduling	Unusual deviation pattern in generation scheduling
IEX/PXIL/HPX settlement reconciliation	Energy trading	Differences between exchange settlement advices and books of account
Payroll anomaly detection	HR	Duplicate PAN; salary above grade; payments after retirement date
Contractor bill frequency analysis	Contracts	Same contractor billing at identical amounts in multiple consecutive months
Coal stock theoretical vs. physical	Fuel management	Cumulative variance between theoretical and physical coal stock

Continuous monitoring suits AT&C losses (monthly, from feeder and DT meters), plant KPIs (daily SCADA data against CERC norms), CEMS data (a monthly review of OCEMS gaps) and the regulatory filing calendar. Three conditions must be met before analytics results are relied on. First, direct read-only query access to the ERP, billing system, SCADA historian and coal measurement system, not management-supplied extracts, which can be filtered. Second, completeness and consistency checks on the data, since an outage register with missing entries or blank GCV fields produces misleading output. Third, human review of every model output before it is treated as a finding: the model shows what is unusual, and the auditor decides whether it is irregular. The internal audit function should keep a documented AI Governance Policy covering tools, validation, human review, retention of consumer data under the DPDP Act 2023, and documentation standards, so that every AI-assisted finding can be explained to the Audit Committee. Audit of the entity's own AI applications is covered in Section 14.8.2.

2.10 Financial Impact Quantification

Every significant audit finding should be quantified. Standard formulas for each entity type and functional area are in Appendix 12. Entity chapters also give the relevant formula alongside each audit procedure.

2.11 Follow-up Audit

Follow-up of open findings, from internal audit and from CAG, CERC/SERC, environmental and other regulators, is part of the reporting cycle in Section 2.13. It covers closure verification (Section 2.13.6), the next rotation auditor's para check (Section 2.13.7) and the Follow-Up Audit Report (Section 2.13.8).

2.12 Audit Committee Relationship

The Audit Committee is the primary governance body to which the internal audit function reports functionally. The Chief Internal Auditor should present quarterly reports covering: status of Annual

Audit Plan; significant findings of the quarter with financial impact and management response; status of previous findings; multi-audit universe status like pending CAG paras; CERC/SERC disallowances; tax demands; environmental notices; emerging risks; and independence declaration. The Chief Internal Auditor must have the right to communicate directly with the Audit Committee without management being present, at least once a year. Where management suppresses a finding, delays corrective action on a significant matter, or interferes with the internal audit function, the Chief Internal Auditor must escalate directly to the Audit Committee without delay.

2.13 Audit Reporting Framework

This section covers two distinct but interconnected reporting frameworks:

- ✓ **Framework A** — In-House Internal Audit Reporting Cycle: the complete cycle from Audit Slip to Final Report to ATR to Follow-up
- ✓ **Framework B** — CAG/Government Audit Reporting Pattern: the structured hierarchy used by the Comptroller and Auditor General of India

2.13.1 Framework A — In-House Reporting Cycle

The Complete Reporting Cycle — 10 Stages:

- ✓ Stage 1: **AUDIT SLIP** — field-level query; issued immediately on identification of potential issue
- ✓ Stage 2: **AUDITEE RESPONSE** — 3 possible outcomes: (a) adequate response → close slip; (b) inadequate response → seek specific clarification; if still inadequate, convert to Audit Para; (c) no response → convert to Audit Para
- ✓ Stage 3: **AUDIT PARA** — formal finding raised when response is inadequate or nil
- ✓ Stage 4: **EXIT CONFERENCE** — discuss all paras with management team before draft report
- ✓ Stage 5: **DRAFT REPORT** — all paras in CCCCE format; management response column blank
- ✓ Stage 6: **MANAGEMENT RESPONSE** — written response to each para within 15 days; vague responses not acceptable
- ✓ Stage 7: **FINAL REPORT** — all paras with management response; issued to Audit Committee
- ✓ Stage 8: **ACTION TAKEN REPORT (ATR)** — management submits ATR; IA verifies physically, not merely files
- ✓ Stage 9: **FOLLOW-UP AUDIT** — next rotation auditor checks status of all previous paras before starting fresh audit
- ✓ Stage 10: **CLOSURE OR PERSISTENT OBSERVATION** — formally closed on verified compliance; escalated if open for 3+ years

Golden Rule: No finding should appear in a Final Report without having first been raised as an Audit Slip. No Audit Para should be raised without giving the auditee an opportunity to respond. No para should be closed without physical verification of compliance by the internal auditor.

2.13.2 Audit Slip — Format and Principles

An Audit Slip is the first formal document raised when the internal auditor identifies a potential issue. It is a query, not a finding. It creates a contemporaneous record; gives the auditee a fair opportunity to explain; and prevents the auditee from later claiming no opportunity was provided.

Standard format: Slip Number (sequential); Date; Audit Period; Area; Addressed to (Name; Designation; Department); Observation (factual — no conclusion; no opinion); Documents Examined; Information/Clarification Required; Reply Required By (specific date — typically 7 working days); Issued by (auditor signature); and Acknowledged by (auditee signature and date).

Key principles: issue one slip per issue, do not club unrelated matters; obtain acknowledgement without this the slip has no standing; maintain a Slip Register tracking all slips issued, responses received, and status.

2.13.3 Audit Para — Categories and Format

Category	Description	Power Sector Examples	Compliance Timeline
Serious Irregularity	Fraud; misappropriation; wilful misrepresentation; major regulatory violation	Coal weighbridge fraud; CEMS manipulation; fictitious contractor payments; PAF inflation	Immediate — Audit Committee within 24 hours
Major Finding	Systemic control failure; financial impact above materiality; material regulatory non-compliance	ACQ penalties not raised; FPA under-billing; RPO non-compliance; DFP breach	30 days
Minor Finding	Isolated control weakness; below materiality but noteworthy	Single DFP deviation; minor procedural lapse; documentation gap	60 days
Observation /Advisory	Process improvement; emerging risk; best practice recommendation	Formalise coal blending policy; suggest cybersecurity upgrade; initiate CCTS registration	90 days

CCCCE Format for Writing Audit Paras:

- ✓ **Criteria** — what should be: the applicable norm; regulation; contract term; or management policy
- ✓ **Condition** — what was found: factual; based on evidence; no opinion at this stage
- ✓ **Cause** — why it happened: root cause; systemic analysis; not blame
- ✓ **Consequence** — financial impact; regulatory risk; operational impact — quantified wherever possible
- ✓ **Recommendation (Essence)** — specific; actionable; time-bound corrective action

Para Numbering Convention: Format: [Entity Code] /[Plant/Unit Name]/ [Financial Year] / [Area Code] / [Serial Number].

Example: [X]GENCO/[Z]TPS/2026-27/FUEL/003. Area codes: FUEL; OPS; ENV; CAPEX; HR; TAX; IT; ESG; MINE; RE; PROC; TREA etc.

Para Register: Every internal audit department must maintain a Para Register tracking: Para Reference; Date of Issue; Category; Area; One-line Summary; Financial Impact; Corresponding Audit Slip; Draft/Final Report Date; Management Response; ATR Received; Action Committed;

Target Date; Status (Open/Partially Closed/Closed/Recurrent/Persistent); IA Verification Date; Closure Date; Remarks.

2.13.4 Draft Report and Exit Conference

The Draft Report contains all audit paras in CCCCE format with the management response column blank, issued to management for formal written response within 15 days. Before issuing, hold an Exit Conference with the auditee management team: present all paras; hear management's initial response; resolve factual errors; agree on response timelines. Minutes should be documented and signed by both parties. No finding should be dropped at exit conference merely because management objects — only factual corrections are acceptable. Management responses that are vague — 'noted; will be complied with' — are not acceptable; specific responses with committed action and timelines must be obtained.

2.13.5 Final Internal Audit Report — Structure

The Final Report follows the format in Appendix 15: executive summary with overall control assessment; scope and methodology; regulatory compliance status; operational performance dashboard; detailed paras in CCCCE format, with management response and the auditor's comment; ESG observations; cybersecurity observations; follow-up status; para status summary; financial impact of internal audit; and conclusion.

2.13.6 Action Taken Report (ATR) — Verification Methodology

An ATR is a formal document submitted by management describing specific action taken on each para. The internal auditor must verify the ATR, not merely file it.

ATR Claim	How Internal Auditor Verifies
Amount recovered from contractor	Bank statement; ledger entry; receipt — not just management assertion
Process SOP issued	Obtain the SOP; verify it is in force; check if staff are aware
Staff trained	Training attendance register; content; assessment results
GCV dispute filed	Obtain filed dispute document; receipt acknowledgement from coal company
Equipment repaired	Physical inspection; maintenance record; test certificate
Insurance renewed	Policy document; premium payment receipt

A para is formally closed only when: ATR received with specific evidence; internal auditor physically verified compliance; root cause is addressed, not just symptom; and no residual risk remains. Where some recommendations are implemented and others pending, mark as Partially Closed with specific details of what remains open.

2.13.7 The Next Rotation Auditor — Para Status Check (5 Steps)

This is the most important continuity mechanism in internal audit. When a new auditor or team takes over, the very first task before commencing any fresh audit work is to check the status of all previous audit paras.

- ✓ Step 1 — Obtain all internal audit reports for the past three years including follow-up reports and special reports
- ✓ Step 2 — Review the Para Register: list all open paras; partially closed paras; persistent paras (3+ years open); and recurrent findings

- ✓ Step 3 — Carry forward open paras: open paras from previous years are automatically carried forward under their original para numbers — they do not need to be re-raised as new paras
- ✓ Step 4 — Record in the Entity Understanding: record the para status in the 'Previous Internal Audit' section of the entity understanding (Section 2.5) before starting any fresh work
- ✓ Step 5 — Cross-reference with CAG Paras: check if any internal audit para corresponds to a pending CAG inspection report or audit report para — if yes, track jointly to avoid duplication

This step ensures: continuity — findings from previous auditors are not lost; accountability — management cannot assume a change of auditor means closure of findings; intelligence — previous findings guide the new auditor on where to focus; and institutional memory — the Para Register is the organisational memory of the audit function.

2.13.8 Follow-Up Audit Report

At the start of every audit cycle, internal audit independently verifies the status of every open finding. It classifies each one as Closed or Partially Closed (Section 2.13.6), Open, Recurrent (closed earlier but the issue has reappeared) or Persistent (open for three consecutive years or more without adequate action; Section 2.13.1). The same discipline applies to findings of external oversight bodies, tracked in the Master Audit Findings Register (Section 14.10). A Follow-Up Audit Report, typically half-yearly, gives: summary status by year and category; the status of each open or partially closed para, with the outstanding action and next step; Persistent Observations, with root cause and a recommendation for direct Board or Audit Committee intervention; Recurrent Findings; and the Financial Impact of Internal Audit, covering recoveries, penalty bills raised, revenue protected and expenditure avoided.

2.13.9 Special Reports (Flash, Special Audit and Pre-Audit)

Flash Report — one page; issued immediately on identification of Serious Irregularity: what was found; estimated financial impact; immediate action required; by whom; by when.

Special Audit Report — issued on completion of a Special Audit (Section 2.4.4): background and trigger; scope; evidence examined; findings stated as facts supported by evidence; financial impact; and recommendations for recovery, process improvement and, where warranted, referral to Vigilance.

Pre-Audit Report — before major external audit such as CAG or CERC prudency check: areas likely to be scrutinized; internal findings in those areas; recommended corrective action before external audit begins.

2.13.10 Framework B — CAG/Government Audit Reporting Pattern

For internal auditors of government-owned power PSUs, CAG audit is the most important external audit framework. Understanding it helps internal audit anticipate what CAG will examine, prepare accurate management responses, track compliance, and use CAG findings as audit intelligence. Besides the three types below, CAG may conduct thematic audits across several entities. It also issues Factual Statements and Draft Paras before a finding is included in an Audit Report.

Type 1 — Supplementary Audit (Section 143(6) Companies Act 2013): CAG reviews the statutory audit report and issues Supplementary Audit Comments, which appear in the Annual Report. Management must respond within 6 weeks. Internal audit pre-reviews the financial statements for likely observations, briefs the finance team, checks the factual accuracy of the response, and tracks whether the previous year's comments have been addressed.

Type 2 — Transaction Audit (Regular Audit):

- ✓ Step 1 — Audit Objection: CAG raises an Audit Objection when a finding is identified, similar to an Audit Slip. Auditee must respond within 7-15 days.
- ✓ Step 2 — Auditee Response: if satisfactory — objection closed; if not — converted to Inspection Report Para.
- ✓ Step 3 — Inspection Report (IR): consolidation of all unresolved objections into an IR issued to the entity. An IR Para marked as Draft Para signals CAG's intent to include it in the formal Audit Report — the last opportunity to settle before Parliamentary visibility.
- ✓ Step 4 — Management Response to IR: typically within 4-6 weeks; must accept or dispute with specific facts; state corrective action; provide timeline.
- ✓ Step 5 — Audit Report Para: selected IR paras included in CAG's Audit Report presented to Parliament (for Central PSUs) or Legislature (for State PSUs).
- ✓ Step 6 — Action Taken Note (ATN): the government/PSU's formal response to Audit Report paras; submitted to Ministry for onward submission to COPU (or PAC, as applicable); must state action taken (not proposed); submitted within stipulated timeline.

Type 3 — Performance Audit: CAG selects specific topics for deep-dive performance audits — for example, Fuel Management of Central Generating Stations (CAG Report No. 35 of 2016), UDAY scheme implementation, and Solar Park development. The process involves an Entry Conference; detailed field audit over several months; Exit Conference; Draft Report shared with management for response; Final Report presented to Parliament or Legislature; ATNs submitted through Ministry to COPU (or PAC, as applicable).

CAG Para Types — Summary:

Para Type	Description	Action Required
Audit Para	Formally included finding in CAG Audit Report; most serious category	ATN submission to Ministry for COPU (or PAC, as applicable); implement corrective action
Factual Note	Flags an important factual situation without constituting a financial irregularity	Management information and awareness; address underlying issue
Draft Para	Signals CAG's intent to include in Audit Report; last opportunity to settle	Immediate management attention; prepare specific factual response with evidence
Critical Observation	Significant finding in Performance Audit involving systemic failure or significant public money	Formal management response; systemic corrective action; ATN submission
Action Taken Note (ATN)	Government/PSU's formal response to Audit Report paras submitted through Ministry to COPU (or PAC, as applicable)	File within stipulated timeline; state specific actions taken; factually verifiable

Internal Audit's Role in CAG Coordination: Before CAG Audit: conduct self-audit of likely examination areas; ensure records are organized; brief department heads on likely CAG focus areas. During CAG Audit: facilitate professionally; respond to objections promptly — delay leads to IR paras; verify independently whether a CAG objection is valid before responding. After Inspection Report: para-wise review; prepare management response draft; verify factual accuracy before submission to CAG; track settlement of each IR para in the IR Para Register. After Audit Report: support ATN preparation; ensure factual accuracy; prepare briefs for COPU (or PAC, as applicable) examination if the entity is called.

2.13.11 The Learning Loop — Converting External Audit Findings into IA Intelligence

When CAG finds something in Plant A — the internal auditor should immediately check the same thing in Plants B, C, and D before CAG gets there.

Learning Loop Process:

- ✓ Step 1 — Intelligence Gathering: after every CAG Inspection Report; CERC disallowance; SERC prudency finding; or environmental SCN — extract the key finding and translate it into a specific audit procedure for similar entities.
- ✓ Step 2 — Add to Audit Programme: the extracted procedure is added to the programme for all similar entities in the next audit cycle.
- ✓ Step 3 — Pre-empt the CAG Finding: if the same issue is found internally before CAG audits that entity — management corrects it; the finding is reported internally; and when CAG comes they find a corrected position.
- ✓ Step 4 — Document the Learning: a section called 'Lessons from External Audit Findings' should be part of every Annual Audit Plan. Refer Chapter 14 and Appendix 11 for common CAG/CERC/SERC finding patterns in the power sector.

2.14 Quality Assurance and Improvement Programme

The internal audit function should have a Quality Assurance and Improvement Programme (QAIP) comprising internal quality assurance (ongoing supervision; self-assessment; working paper reviews by the CIA; feedback from auditees and Audit Committee) and external quality assessment (independent assessment by a qualified external assessor at least once every five years, results reported to the Audit Committee). For detailed QAIP requirements, refer ICMAI IAAS and Global Internal Audit Standards™ (2024 Edition).

3. GLOSSARY OF TERMS — POWER SECTOR

3.0 Introduction

A sound understanding of the terminology used in the power sector is essential for an internal auditor to plan and execute audit assignments effectively. The power sector has its own technical, regulatory, commercial, and financial vocabulary, much of which is unique to the sector and not found in general audit or accounting literature. This glossary provides definitions of key terms used in this Guidance Note and in the power sector generally, organised alphabetically within broad thematic groups. Where a term has a specific regulatory definition under the Electricity Act 2003, CERC Regulations, or other applicable legislation, that definition is adopted or referenced. Where no specific regulatory definition exists, a working definition is provided for the purpose of this Guidance Note.

3.1 Regulatory and Legal Terms

Act — Unless otherwise specified, the Electricity Act 2003 (Act No. 36 of 2003) as amended from time to time; the principal legislation governing the power sector, which de-licenses generation, provides for licensing of transmission, distribution and trading, constitutes or continues CEA, CERC, SERCs and APTEL, and governs tariff determination, open access and consumer protection.

Annual Revenue Requirement (ARR) — The total revenue requirement of a distribution or transmission licensee for a given financial year as approved by the concerned SERC/CERC, forming the basis for tariff determination.

Appellate Tribunal for Electricity (APTEL) — The statutory appellate body constituted under Section 110 of the Electricity Act 2003 to hear appeals against orders of CERC and SERCs, whose orders are binding on the parties.

Availability Based Tariff (ABT) — A tariff mechanism applicable to central generating stations under which the generating station receives capacity charges for declared availability irrespective of actual generation, and energy charges for actual generation; deviations between scheduled and actual generation are settled through the Deviation Settlement Mechanism.

Beneficiary — In the context of central generating stations, the entity — typically a state DISCOM or state utility — allocated a share of the capacity of a generating station under a Long Term PPA, and obligated to pay capacity charges regardless of actual drawl.

Central Electricity Authority (CEA) — A statutory body constituted under Section 70 of the Electricity Act 2003, responsible for technical standards for construction, connectivity, and metering; national electricity planning; and collection and publication of electricity generation data.

Central Electricity Regulatory Commission (CERC) — The central regulatory commission constituted under Section 76 of the Electricity Act 2003, which determines tariff for central generating stations and inter-state transmission; regulates inter-state trading; and issues market regulations.

Commission — Refers to CERC or SERC as the context requires.

Control Period — The period for which CERC determines tariff norms under the Terms and Conditions of Tariff Regulations; the current Control Period is 2024-29.

Deemed Generation — Generation that a renewable energy generator is entitled to claim even when actual generation is lower than scheduled, due to grid unavailability or backing-down by the grid operator.

Deviation Settlement Mechanism (DSM) — The mechanism for settling deviations between scheduled and actual generation or drawl in each time block under the CERC DSM Regulations, with deviation charges now linked to the market clearing price rather than to grid frequency; DSM replaced the earlier Unscheduled Interchange (UI) mechanism.

Distribution Licensee — A person licensed under Section 14 of the Electricity Act 2003 to supply electricity to consumers in a notified area of supply.

Generating Company — A company or body corporate or association or body of individuals that owns or operates or maintains a generating station, as defined in Section 2(28) of the Electricity Act 2003.

Indian Electricity Grid Code (IEGC) — The code issued by CERC under Section 79(1)(h) governing operation and maintenance of the transmission system, connectivity of generating stations, and scheduling and despatch of electricity.

Joint Electricity Regulatory Commission (JERC) — A regulatory commission constituted for more than one state or union territory, performing the functions of SERCs; JERC orders carry the same authority as SERC orders.

Licensee — A person granted a licence under Section 14 of the Electricity Act 2003 to transmit, distribute or trade in electricity, the licence defining the area of operation, conditions of service and obligations; generation does not require a licence.

Load Factor — The ratio of actual energy consumed or generated during a given period to the maximum possible energy at peak demand or installed capacity, expressing the evenness of demand or generation profile.

Multi-Year Tariff (MYT) — A tariff framework under which SERC determines tariff for a distribution or transmission licensee for multiple years — typically three to five years — with annual true-up provisions.

Open Access — The right of any person to use the transmission or distribution system of a licensee for conveyance of electricity on payment of applicable charges including transmission charges, wheeling charges, cross-subsidy surcharge, and additional surcharge, as governed by Section 42 of the Electricity Act 2003 and SERC/CERC regulations.

Renewable Purchase Obligation (RPO) — The obligation of distribution licensees, open access consumers, and captive users to procure a specified minimum percentage of their consumption from renewable energy sources, with non-compliance attracting penalties.

Scheduled Generation — The quantum of generation from a generating station for a given time block as agreed through the scheduling process between the generating station and RLDC/SLDC, forming the basis for energy charge payments; capacity charges are paid on Declared Capacity.

State Electricity Regulatory Commission (SERC) — The regulatory commission constituted by each state government under Section 82 of the Electricity Act 2003, determining retail tariff; regulating distribution and intra-state transmission; setting RPO targets; and issuing state grid codes.

System Operation — The activity of operating the transmission system including real-time monitoring, scheduling and despatch, frequency regulation, outage coordination, and system restoration, performed by NLDC/RLDCs/SLDCs.

Tariff Order — An order issued by CERC or SERC determining the tariff payable to or by a licensee or generating company for a specified period.

Trading Licensee — A person licensed under Section 14 of the Electricity Act 2003 to engage in trading of electricity, and required to comply with CERC's trading margin regulations and other applicable regulations.

True-up — The process of reconciling actual revenue requirement of a licensee or generating company with provisional amounts allowed in the tariff order, with petitions filed to CERC/SERC with supporting data including auditor certificates where required.

Unscheduled Interchange (UI) — The difference between actual generation or drawl and scheduled generation or drawl in a given time block, substantially replaced by DSM but with legacy UI settlements that may still appear in accounts of entities operating before DSM migration.

Wheeling — The use of the transmission or distribution system of a licensee by another person for conveyance of electricity on payment of wheeling charges; the mechanism through which open access consumers receive power through the licensee's network.

3.2 Generation and Technical Terms

Auxiliary Power Consumption (APC) / Auxiliary Consumption — The electricity consumed by auxiliary equipment of a generating station such as fans, mills, pumps, ESP, and lighting, expressed as a percentage of gross generation; CERC prescribes normative APC under the 2024-29 Tariff Regulations.

Captive Generating Plant — A power plant set up primarily for own use under Section 2(8) of the Electricity Act 2003; under Rule 3 of the Electricity Rules 2005, captive users must hold not less than 26% of the ownership and consume not less than 51% of the aggregate electricity generated in a year.

Commercial Operation Date (COD) — The date from which a generating unit or transmission element is declared commercially operational and from which tariff starts to accrue.

Declared Capacity (DC) — The generating capacity in MW declared by a generating station to SLDC/RLDC for a given time block, forming the basis for capacity charges under ABT.

Design Energy — For hydro power stations, the quantum of electricity that can be generated in a year of 90% dependability from a given installed capacity as determined during project design.

Flue Gas Desulphurisation (FGD) — A system installed in thermal power plants to remove SO_2 from flue gases before emission. Whether FGD or another SO_2-control measure is required, and by when, depends on the plant's location category (A, B or C) under MoEFCC notification S.O. 3305(E) dated 7 December 2015, as amended, including the notification of 11 July 2025. The applicable requirement for each plant must therefore be verified under the current framework (Section 8.4; Appendix A2.3). For FGD-installed units, CERC has introduced specific O&M norms under the 2024-29 Tariff Regulations.

Gross Calorific Value (GCV) — The heat energy released per unit weight of coal when completely combusted, expressed in Kcal/kg, which is the primary parameter for coal quality determination and billing under FSA.

Heat Rate — Refer Station Heat Rate (SHR) below; both terms are used interchangeably in the power sector.

Hydro Purchase Obligation (HPO) — The hydropower component of the RPO trajectory notified by the Ministry of Power Order dated 22 July 2022, applicable from FY 2023-24.

Installed Capacity — The total generating capacity of a power plant in MW as installed, irrespective of actual generation; the basis for computing Plant Load Factor and reference point for CERC capacity charge norms.

Mega Power Project — A thermal project with capacity of 1,000 MW or more, or a hydro project with 500 MW or more, eligible for certain tax and customs duty concessions.

Merchant Power Plant — A generating station that sells electricity primarily in the short-term market without a long-term PPA, not subject to CERC Section 62 tariff regulation, with revenue determined by market prices.

Normative Annual Plant Availability Factor (NAPAF) — The normative availability prescribed by CERC for capacity charge entitlement purposes, currently 85% for thermal generating stations under CERC 2024-29 Regulations.

Plant Availability Factor (PAF) — The percentage of time during a given period for which a generating unit or station is available for generation, whether or not actually generating; CERC prescribes normative PAF of 85% for thermal stations under 2024-29 Regulations.

Plant Load Factor (PLF) — The ratio of actual energy generated to the maximum possible energy at installed capacity over a given period; a measure of capacity utilisation distinct from PAF — a plant may have high availability but low PLF if not scheduled to generate.

Pumped Storage Project (PSP) — A hydroelectric facility that stores energy by pumping water to an upper reservoir during low demand and releases it to generate power during peak demand; Ministry of Power issued Guidelines to Promote Development of Pump Storage Projects in April 2023.

Renovation and Modernisation (R&M) — Capital works undertaken to extend the life of an existing generating unit or improve its performance; R&M expenditure may be treated as capital expenditure for tariff purposes if it meets CERC criteria.

Specific Oil Consumption (SOC) — The quantity of fuel oil consumed per unit of electricity generated, expressed in ml/kWh; CERC prescribes normative SOC of 0.30 ml/kWh for thermal stations under 2024-29 Regulations.

Station Heat Rate (SHR) / Heat Rate — The quantity of heat energy input required to generate one unit (kWh) of electricity, expressed in Kcal/kWh; the primary efficiency parameter for thermal generating stations, with CERC prescribing normative SHR — for example, 2,340 Kcal/kWh for supercritical 500 MW units under 2024-29 Regulations.

Ultra Mega Power Project (UMPP) — A generating project with capacity of 4,000 MW or more developed through tariff-based competitive bidding under Section 63 of the Electricity Act 2003, implemented through an SPV; its audit considerations differ from those of Section 62 projects.

3.3 Transmission Terms

General Network Access (GNA) — The framework introduced by CERC under the Connectivity and General Network Access to ISTS Regulations 2022, replacing the earlier LTA and MTOA frameworks, providing flexible access to ISTS for generators and bulk consumers.

Inter-State Transmission System (ISTS) — The transmission system for conveyance of electricity across state boundaries, largely owned by PGCIL and other transmission licensees, operated by Grid-India and regulated by CERC, with charges shared among users under the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations 2020.

ISTS Waiver — Waiver of ISTS charges for renewable energy projects under Ministry of Power orders, given in full to projects commissioned up to 30 June 2025 and reduced by 25% each year thereafter for projects commissioned up to June 2028, with separate timelines for storage and green hydrogen projects.

Long Term Access (LTA) — The earlier framework for long-term access to ISTS, now replaced by General Network Access (GNA) under CERC Connectivity Regulations 2022; LTA commitments made prior to the change are being transitioned to GNA.

Point of Connection (PoC) — The earlier methodology for apportioning ISTS charges among users by injection and drawl nodes, replaced from November 2020 by the CERC Sharing Regulations 2020; PoC-based bills may still appear in legacy reconciliations.

Security Constrained Economic Despatch (SCED) — A mechanism operated by Grid-India for economic despatch of generating stations taking into account transmission security constraints, to minimise overall cost of power while maintaining grid stability; mandatory for all ISTS-connected thermal stations.

Transmission Service Agreement (TSA) — The agreement between the long-term transmission customer and the central transmission utility governing terms and conditions of transmission service.

3.4 Distribution Terms

Aggregate Technical and Commercial Losses (AT&C Losses) — A comprehensive measure of DISCOM efficiency representing total losses — technical losses in lines and transformers as well as commercial losses from theft, billing errors, and collection shortfalls — computed as: AT&C Loss% = [1 − (Units Billed × Collection Efficiency ÷ Input Units)] × 100.

Distribution Transformer (DT) Metering — Installation of energy meters at distribution transformers to measure input energy at DT level, enabling feeder-level and DT-level energy accounting and AT&C loss computation; 100% DT metering is a target under RDSS.

Electricity Ombudsman — An authority appointed under Section 42(6) of the Electricity Act 2003 to redress consumer grievances not resolved by the Consumer Grievance Redressal Forum.

Feeder — A distribution line carrying electricity from a substation to consumers, classified as urban, rural, or agricultural for energy accounting and subsidy purposes.

Fuel and Power Purchase Cost Adjustment (FPPCA) — The automatic monthly pass-through to consumers of variations in fuel and power purchase cost from the cost assumed in the tariff order, required by the Electricity (Amendment) Rules 2022 and subject to SERC true-up.

Regulatory Asset (RA) — Revenue expenditure or under-recovery of costs that a licensee is permitted by SERC to defer for recovery in future tariff periods rather than including in current tariff.

Revamped Distribution Sector Scheme (RDSS) — A scheme launched by the Government of India in 2021, subsuming IPDS and DDUGJY, aimed at improving operational and financial health of DISCOMs through smart metering, infrastructure upgradation, feeder separation, and AT&C loss reduction with performance-linked grant disbursement.

Smart Meter — A digital electricity meter capable of two-way communication with the utility's Head End System, enabling remote reading, real-time consumption monitoring, tamper detection, and prepaid functionality; mandatory rollout of 250 million smart meters is a key RDSS target.

3.5 Coal, Mining and Fuel Supply Terms

Annual Contracted Quantity (ACQ) — The quantity of coal that a coal company is obligated to supply to a generating company under the Fuel Supply Agreement in a given year; shortfall in ACQ supply attracts graded penalties.

Coal Grade — Classification of non-coking coal into 17 grades (G1 to G17) by GCV band in steps of 300 Kcal/kg, G1 being above 7,000 Kcal/kg; the grade established by third-party sampling determines the price billed under the FSA.

Coal Linkage — The allocation of a specified quantity of coal from a colliery to a thermal power station on a long-term basis, forming the basis for FSA execution and allocated through the SHAKTI policy.

Coal Mines (Special Provisions) Act 2015 — The legislation that enabled fresh allocation of coal blocks following the Supreme Court's 2014 order cancelling earlier allocations; captive coal blocks allotted under this Act carry specific obligations including revenue share, production targets, and monitoring committee compliance.

District Mineral Foundation (DMF) — A statutory trust established under the MMDR Act 1957 for welfare of persons and areas affected by mining; companies operating captive coal mines must contribute 10% of royalty for mines allotted on or after 12 January 2015 and 30% for earlier mines.

e-Auction Coal — Coal sold by CIL through electronic auction at market-determined prices typically higher than FSA notified prices.

FOR (Free on Rail) — A price basis under which the seller delivers coal into railway wagons at the loading point and the buyer bears freight from that point; CIL notified prices for FSA coal are on this basis, with railway freight paid separately by the generating company.

Fuel Price Adjustment (FPA) — The mechanism for passing through actual variations in fuel cost to beneficiary DISCOMs over and above the normative fuel cost allowed in the tariff order, computed monthly and billed to beneficiaries.

Fuel Supply Agreement (FSA) — The agreement between a generating company and a coal company governing supply of coal including quantity (ACQ), quality (GCV), price, and shortfall penalty provisions.

Letter of Assurance (LoA) — A document issued under the SHAKTI Policy by CIL to a generating company providing assurance of coal linkage subject to specified conditions.

Mine Developer and Operator (MDO) — An entity contracted by a coal block allottee (GENCO) to develop and operate the captive coal mine on its behalf, with the allottee retaining ownership and regulatory responsibility.

National Mineral Exploration Trust (NMET) — A trust established under the MMDR Act 1957 for regional and detailed mineral exploration; captive mine operators must contribute 3% of royalty to NMET.

Overburden (OB) and Strip Ratio — Overburden is the rock and soil overlying a coal seam that must be removed to access coal; the Strip Ratio or OB:Coal ratio is a key operational parameter specified in the mine plan approved by the Ministry of Coal.

Reserve Price — A per-tonne statutory payment obligation imposed on captive coal block allottees under the Coal Mines (Special Provisions) Act 2015 and the allotment order issued by the Ministry of Coal, payable to the coal-bearing State Government where so prescribed under the applicable allotment methodology/order; determined at the time of auction or allotment and escalating annually based on a formula prescribed by the Ministry of Coal linked to specified price indices. For Schedule II auctioned blocks, Revenue Share (as a percentage of coal value at notified price, bid at auction) is payable in addition to the Reserve Price.

SHAKTI Policy — The Scheme for Harnessing and Allocating Koyala Transparently in India introduced by Ministry of Coal in 2017, providing for allocation of coal linkages through Letters of Assurance (LoA); LoA conditions including Bank Guarantee submission, quantity drawl, and e-auction proportion are ongoing compliance obligations.

Transit Loss — The difference between coal weight at loading and at destination due to inherent losses during rail transportation; CERC recognises normative transit loss for tariff purposes and claims above norm must be supported by railway documents.

3.6 Renewable Energy Terms

Battery Energy Storage System (BESS) — A grid-scale energy storage system using electrochemical batteries to store electrical energy and release it as required, with key performance parameters including Round Trip Efficiency (RTE), State of Charge (SoC), and cycle life; the Energy Storage Obligation is set by the Ministry of Power Order dated 22 July 2022.

Capacity Utilisation Factor (CUF) — The ratio of actual energy generated to maximum possible energy at installed capacity over a given period; the primary performance metric for solar and wind projects and typically a guaranteed parameter under PPAs.

Energy Storage Obligation (ESO) — The obligation on distribution licensees, open access consumers, and captive generating plants to procure or develop a specified quantum of energy storage capacity alongside renewable energy, as notified by the Ministry of Power vide Order dated 22 July 2022 specifying the RPO and ESO trajectory up to FY 2029-30; commencing at 1% in FY 2023-24 and rising to 4% by FY 2029-30.

Green Day Ahead Market (G-DAM) — A power exchange market segment specifically for trading of renewable energy certified as green power on a day-ahead basis, launched in October 2021 on IEX and later on PXIL and HPX.

Performance Ratio (PR) — A measure of solar power plant performance — the ratio of actual energy output to theoretical energy output based on incident solar irradiation, normalised for system losses; a PR above 80% is generally considered satisfactory.

Renewable Energy Certificate (REC) — A market-based instrument representing the environmental attributes of one MWh of electricity generated from renewable sources, issued by NLDC and traded on power exchanges to enable obligated entities to meet RPO.

Round Trip Efficiency (RTE) — The ratio of energy output from a BESS to energy input during charging; typical RTE for lithium-ion BESS is 85–92%, and RTE is a key contractual guarantee parameter in BESS procurement contracts.

3.7 Energy Exchange and Carbon Market Terms

Carbon Credit Trading Scheme (CCTS) — A domestic carbon market mechanism established under Section 14AA of the Energy Conservation (Amendment) Act 2022, with the scheme notified by the Ministry of Power vide S.O. 2825(E) dated 28 June 2023; BEE is the administrator, Grid Controller of India Limited (Grid-India) operates the National Carbon Registry, and CERC regulates trading of Carbon Credit Certificates (CCCs) on power exchanges under the CERC (Terms and Conditions for Purchase and Sale of Carbon Credit Certificates) Regulations 2026.

Day Ahead Market (DAM) — The most liquid power exchange segment where electricity is traded for delivery on the following day through double-sided closed auction for each 15-minute time block.

Energy Savings Certificate (ESCert) — A certificate issued under the PAT scheme to Designated Consumers who achieve energy savings beyond their assigned target; tradeable on power exchanges to enable entities that have not achieved their targets to meet their compliance obligation.

High Price Day Ahead Market (HP-DAM) — A power exchange market segment with a higher price ceiling than regular DAM, introduced during periods of high demand scarcity.

Real Time Market (RTM) — A power exchange market segment for trading of electricity in 15-minute time blocks on a near-real-time basis, with gate closure one hour before delivery, launched in June 2020.

Term Ahead Market (TAM) — A power exchange market segment in which Term Ahead Contracts are transacted for physical delivery of electricity on T+2 or later, including approved daily, weekly, monthly and other longer-duration contracts. CERC has permitted longer-duration TAM contracts extending beyond the erstwhile 11-day limit, subject to the contract specifications and approvals applicable from time to time.

3.8 ESG and Sustainability Terms

Business Responsibility and Sustainability Report (BRSR) — A mandatory sustainability disclosure framework prescribed by SEBI, applicable to the top 1,000 listed companies by market capitalisation from FY 2022-23, requiring disclosure on nine principles covering environment, society, and governance.

Continuous Emission Monitoring System (CEMS) — An automated system installed at thermal plant stacks to continuously measure and record emissions of pollutants including SO_2, NO_x, and particulate matter, with data transmitted to CPCB's OCEMS portal in real time.

GHG Protocol — The Greenhouse Gas Protocol Corporate Accounting and Reporting Standard, an internationally accepted framework for measuring and reporting greenhouse gas emissions, classifying emissions into Scope 1 (direct), Scope 2 (indirect from purchased energy), and Scope 3 (value chain).

Online Continuous Emission Monitoring System (OCEMS) — The CPCB web portal to which CEMS data from thermal power plants is transmitted continuously in real time, used by environmental regulators to monitor compliance.

Perform Achieve and Trade (PAT) Scheme — An energy efficiency scheme administered by BEE under the Energy Conservation Act 2001, under which Designated Consumers including large thermal power plants are assigned specific energy consumption targets; DCs achieving targets beyond assigned levels earn ESCerts.

Scope 1 Emissions — Direct GHG emissions from sources owned or controlled by the entity such as fuel combustion in boilers, process emissions, and company vehicle emissions.

Scope 2 Emissions — Indirect GHG emissions from consumption of purchased electricity, heat, or steam; relevant for mine operations and plant auxiliary systems purchasing electricity from the grid.

Scope 3 Emissions — All other indirect GHG emissions in the value chain including employee travel, supply chain, transmission losses, and end-use of electricity generated, currently reported on a voluntary basis in India under BRSR Leadership Indicators.

Zero Liquid Discharge (ZLD) — A water management approach in which all wastewater generated by an industrial facility is treated and reused within the plant with no discharge to external water bodies; mandatory for new thermal power plants in water-stressed areas under MoEFCC standards.

3.9 IT, Cybersecurity and Digital Terms

Distributed Control System (DCS) — An industrial control system used in power plants to control and monitor process parameters such as boiler temperature, turbine speed, and auxiliary equipment; part of the OT infrastructure that must be secured against cybersecurity threats.

Head End System (HES) — The central software system that communicates with smart meters in the field, collects meter data, and provides the interface between smart meters and the DISCOM's back-office systems.

IEC 62443 — A series of international standards for Industrial Automation and Control System (IACS) security, providing a zone and conduit security model applicable to OT systems including DCS, SCADA, and PLC systems in power plants.

Operational Technology (OT) — Hardware and software systems that detect or cause changes through direct monitoring and control of physical devices in industrial environments including power plants and substations, such as DCS, SCADA, PLCs, and energy management systems; governed by IEC 62443 and CEA Cyber Security Guidelines 2021.

SCADA (Supervisory Control and Data Acquisition) — A control system architecture used in power plants, substations, and load despatch centres for real-time monitoring and control of electrical equipment; critical operational infrastructure and a primary target of cybersecurity attacks in the power sector.

3.10 Financial and Accounting Terms

Advance Against Depreciation (AAD) — Under earlier CERC tariff regulations, a mechanism to front-load depreciation recovery in initial years to assist debt servicing; phased out in subsequent regulations but may still appear in accounts of older projects.

Capital Spares (Initial) — Spare parts of a capital nature held for use in the event of breakdown of major equipment; CERC allows Capital Spares (Initial) up to 4% of capital cost as part of the capital cost for tariff purposes.

Incentive — Under the CERC Tariff Regulations 2024-29, the payment to which a thermal generating station is entitled from beneficiaries for scheduled energy (ex-bus) in excess of the energy corresponding to the normative annual Plant Load Factor (PLF), at the rates specified in the Regulations separately for peak and off-peak hours. Incentive is linked to scheduled generation (PLF), not to availability (PAF); availability above the normative level only secures full recovery of capacity charges.

Interest During Construction (IDC) — Interest charges incurred on loans drawn for capital works during the construction period before project commissioning; IDC is capitalised as part of project cost and forms part of capital cost admitted by CERC/SERC for tariff determination.

O&M Expenses — Operation and Maintenance expenses of a generating station or transmission system; CERC prescribes normative O&M per MW per year indexed for inflation, against which actual O&M is compared in tariff true-up.

Regulatory Deferral Account — An account used under Ind AS 114 to recognise regulatory assets and regulatory liabilities arising from rate-regulated activities of power sector entities; Ind AS 114 is an interim standard available to first-time adopters of Ind AS that have rate-regulated activities, including many DISCOMs and transmission utilities.

Tariff Components — Fixed Charges comprising Return on Equity, Depreciation, O&M Expenses, Interest on Loan, and Interest on Working Capital; and Variable Charges comprising energy charge based on normative fuel cost at normative SHR.

Working Capital Norm — Under CERC Tariff Regulations 2024-29, normative working capital for a coal-based station comprises fuel stock for 10 days (pit-head) or 20 days (non-pit-head), advance payment for 30 days' fuel cost, maintenance spares at 20% of O&M expenses, receivables of 45 days of capacity and energy charges, and one month's O&M expenses, with interest allowed at SBI one-year MCLR plus 350 basis points. This tariff norm is distinct from the CEA coal stocking norm, which prescribes the minimum physical stock a plant must hold according to its distance from the source mine (Section 8.2.3).

3.11 Miscellaneous Terms

Chief Internal Auditor (CIA) — The head of the internal audit function, responsible for planning, directing, and reporting on the internal audit activity; accountable to the Audit Committee for functional independence and effectiveness.

Competent Authority — The authority empowered to take a specific decision or grant a specific approval under applicable law, regulation, or company policy; in the context of Delegation of Financial Powers, the officer at the appropriate level whose approval is required for a given transaction value or nature.

Delegation of Financial Powers (DFP) — The document issued by the Board or management specifying the financial authority delegated to various levels of management in terms of transaction value and nature of expenditure.

Force Majeure — Events or circumstances beyond the reasonable control of a party to a contract that prevent or delay performance of contractual obligations; in power sector contracts, force majeure provisions are significant for PPAs, FSAs, and O&M contracts.

Measurement Book (MB) — A register maintained in prescribed format for recording measurements of work done by contractors at a construction or maintenance site; the primary basis for contractor bill certification and payment.

Propriety — The quality of being appropriate, reasonable, and in the best interest of the organisation, as distinguished from merely being legal or procedurally regular; propriety audit examines whether expenditure, though legally sanctioned, was prudent and justified in the public interest.

3.12 Forthcoming Terminology

The following terms are associated with draft legislations and proposed regulations listed in Section 4.5.1. They are not yet given effect in Indian power sector legislation but are increasingly appearing in entity documents, Board papers, management discussions, and regulatory correspondence. Internal auditors should be aware of their meaning and monitor regulatory developments in these areas.

Article 6 Credits — Carbon credits generated and transferred under Article 6 of the Paris Agreement between countries through bilateral agreements; India has executed bilateral agreements for Article 6 credit transfers.

Carbon Border Adjustment Mechanism (CBAM) — A mechanism introduced by the European Union to impose a carbon price on imports of carbon-intensive products from countries without equivalent carbon pricing; Indian power companies with EU lenders, EU export exposure, or EU equipment supply chains should monitor CBAM implications; the definitive phase began on 1 January 2026.

Energy Community — A group of consumers and prosumers sharing locally generated energy within a defined geographical boundary; an emerging regulatory concept relevant to DISCOMs, net metering frameworks, and rooftop solar aggregation.

Just Transition — The process of moving away from coal-dependent energy systems in a manner that is fair and inclusive for workers and communities affected — including mine closures, plant decommissioning, and employment transition programmes.

Virtual Power Plant (VPP) — An aggregation of distributed energy resources such as rooftop solar, small BESS, and EV charging, managed as a single entity for grid services; CERC is expected to issue VPP regulations under which DISCOMs and aggregators will have new compliance obligations.

4. OVERVIEW OF POWER SECTOR

4.0 Introduction

A sound understanding of the power sector — its structure, scale, ownership, regulatory framework, financial mechanics, policy environment, and current challenges is a prerequisite for effective internal audit. An internal auditor who understands how electricity is generated, transmitted, distributed, and traded; how tariffs are determined; what the key performance metrics mean; and what the major policy developments are, is far better equipped to identify risks, ask the right questions, and evaluate management responses.

This chapter provides an overview of India's power sector for internal auditors, particularly those who may be new to the sector or who are transitioning from audit of other industries.

4.1 Structure of India's Power Sector

India's power sector is organised around four principal activities, namely generation, transmission, distribution, and trading with load management and system operation as a critical supporting function.

4.1.1 Generation

Thermal generation from coal, gas, and oil-based plants remains the backbone of India's electricity supply, contributing the majority of actual electricity generated. Thermal plants are capital-intensive, fuel-dependent, and subject to extensive CERC/SERC tariff regulation.

Hydro generation contributes significantly and is subject to hydrological variability; large hydro projects involve complex regulatory, environmental, and social considerations including dam safety and water-sharing.

Nuclear power is generated under AERB oversight with very low variable costs and high availability.

Renewable generation from solar, wind, biomass and small hydro now represents the largest share of newly added capacity. Battery Energy Storage Systems (BESS) are increasingly co-located with RE projects to address intermittency.

4.1.2 Transmission

Electricity is transmitted over high-voltage lines from generating stations to load centres. The inter-state transmission system (ISTS), largely owned by PGCIL and other transmission licensees and operated by Grid-India, carries electricity across state boundaries. Intra-state transmission systems are owned and operated by State Transmission Utilities (STUs). The transmission system is managed through a hierarchy of load despatch centres like NLDC at the national level; five RLDCs at the regional level; and SLDCs at the state level, responsible for scheduling, despatch, and grid security.

4.1.3 Distribution

Distribution companies (DISCOMs) receive electricity at high voltage from the transmission system and supply it to end consumers at lower voltages. DISCOMs are the interface between the bulk power system and the end consumer and are most directly affected by AT&C losses, which combine technical losses in the network with commercial losses from theft and from billing and collection inefficiencies.

4.1.4 Trading, Exchanges and System Operation

Short-term electricity trading occurs through power exchanges like IEX, PXIL and HPX, and through bilateral arrangements. Power exchanges provide platforms for Day Ahead Market, Real Time Market, Term Ahead Market, and Green Day Ahead Market; electricity futures are traded separately on commodity exchanges under SEBI regulation. Load Despatch Centres schedule generation, manage grid frequency, coordinate outages, and settle energy accounts. Their functioning is critical to grid security and the accuracy of energy accounting.

4.2 Key Statistics — Current Position (as at 31 March 2025)

Parameter	Current Position (as at 31 March 2025)
Total Installed Capacity	Approximately 475 GW (March 2025)
Thermal Installed Capacity	Approximately 247 GW (coal, lignite, gas, diesel)
Hydro Installed Capacity (large)	Approximately 47 GW
Nuclear Installed Capacity	Approximately 8.2 GW
Renewable Installed Capacity (excluding large hydro)	Approximately 172 GW
Solar Installed Capacity	Above 100 GW
Wind Installed Capacity	Above 50 GW
Non-Fossil Share of Installed Capacity	Above 45%
Total Electricity Generation	Above 1,800 Billion Units (BU) in 2024-25
Peak Demand Met	Approximately 250 GW in 2024-25
Transmission Lines (220 kV and above, all-India)	Approximately 4.9 lakh circuit kilometres
National AT&C Losses	Approximately 15% national average (2024-25)
Non-Fossil Capacity Target by 2030	500 GW (national target); 50% non-fossil share (updated NDC)
India's Global Rank in Generation	Third largest in the world

4.3 Stakeholder Map — Audit Relevance

4.3.1 Primary Entities — Subject to Internal Audit

These are the entities listed in Section 1.2.1: GENCOs (including integrated coal mines); TRANSCOs; DISCOMs; NLDC, RLDCs and SLDCs; and power exchanges, to the extent of compliance and market operations audit.

4.3.2 Reference Entities — Not Subject to IA Under This GN

- ✓ **Ministry of Power (MoP)** — Policy-making; schemes; national electricity plan
- ✓ **Ministry of Coal (MoC)** — Coal block allocation; SHAKTI policy; mine plan and closure plan approval; oversight of CIL and subsidiaries
- ✓ **Ministry of New and Renewable Energy (MNRE)** — RE policy; solar and wind programmes; green hydrogen mission
- ✓ **CERC** — Central tariff regulation; market regulations; inter-state open access; grid standards
- ✓ **SERCs / JERCs** — State tariff determination; retail supply; intra-state open access; RPO; consumer protection

- ✓ **Central Electricity Authority (CEA)** — Technical standards; national electricity planning; equipment approval
- ✓ **APTEL** — Appellate jurisdiction over CERC and SERC orders
- ✓ **MoEFCC; CPCB; SPCBs** — Environmental standards and enforcement
- ✓ **DGMS** — Mine safety regulation
- ✓ **BEE** — Energy efficiency; PAT scheme; carbon credit market administration

4.3.3 Ancillary Entities — Appear as Counterparties in Audit

- ✓ **Coal India Limited (CIL) and subsidiaries, SCCL** — As FSA counterparty; GCV disputes; ACQ compliance
- ✓ **Power Finance Corporation (PFC) and REC Limited** — As lenders; loan covenant compliance; RDSS grant disbursement
- ✓ **SECI** — As RE auction agency; PPA compliance for SECI-auctioned projects
- ✓ **Independent Power Producers (IPPs)** — As counterparties in DISCOM power purchase audit
- ✓ **Power Traders** — As intermediaries in bilateral power trading
- ✓ **Banks and Financial Institutions** — As lenders; BRS verification; LC and guarantee tracking

4.4 Legal and Regulatory Framework — Summary

The complete matrix of laws, regulations and policies, with the entities they apply to and their audit implications, is in Chapter 5 and Appendix 8.

4.5 Government Schemes and Policy Framework

The government schemes with a direct bearing on internal audit are summarised in Appendix 9, with their audit implications and chapter references. They are SHAKTI, PM-KUSUM, FAME-II (succeeded by PM E-DRIVE), RDSS, the National Green Hydrogen Mission, the Pump Storage Project Guidelines 2023 and PM Surya Ghar. The policy and regulatory instruments are covered in Chapter 5. They are the National Electricity Policy and Plan, the National Tariff Policy, the CEA Cyber Security Guidelines, the Electricity (Amendment) Rules 2023, the Energy Storage Obligation Order, CCTS 2023 and the CERC Tariff Regulations 2024-29. All KPI benchmarks in this Guidance Note refer to the CERC 2024-29 norms unless stated otherwise.

4.5.1 Forward-Looking — Draft Legislations and Proposed Regulations

The instruments below were under consultation or pending at the date of publication and have no legal force, so they must not be cited as operative law. When one is notified, apply it from its effective date using the chapter shown. Review this list in each annual risk assessment, and monitor notifications from MoP, MNRE, CERC, BEE, MoEFCC and the Ministry of Finance.

Pending Instrument	Key Provisions / Scope	Audit Action When Enacted	Refer
Electricity (Amendment) Bill 2025 — draft	Supply by more than one DISCOM in an area using a shared distribution network,	None until enacted — internal auditors must NOT cite these provisions as	Section 5.1; Ch.12

released by MoP for consultation in October 2025; not enacted at the date of publication	subject to SERC oversight; elimination of cross-subsidy for manufacturing enterprises, railways and metro railways within five years; SERC may exempt DISCOMs from the obligation to supply consumers with demand above 1 MW; Electricity Council chaired by the Union Power Minister; penalty for non-compliance with renewable purchase obligations; revised provisions on removal of regulatory commission members.	operative law. Monitor the Bill's status; when enacted, update the DISCOM licensing, tariff, cross-subsidy and RPO audit procedures from the effective date.	
National Electricity Policy — Revised Draft	Enhanced RE and energy storage targets; just transition from coal; updated competitive electricity market framework.	Monitor — when notified, update annual audit plan for revised RPO/ESO benchmarks.	Section 5.5; Ch.10
IEGC 2023 — proposed amendments	RE integration norms; energy storage scheduling; market coupling; ancillary services framework.	New scheduling and DSM audit areas for GENCOs, TRANSCOs, and LDCs when notified.	Ch.8; Ch.11
CERC Market Coupling Regulations	Unifying price discovery across IEX, PXIL and HPX power exchanges — revised settlement mechanism.	Exchange settlement and compliance audit procedures will require update when notified.	Ch.13
CERC Offshore Wind Tariff and Connectivity Regulations	Specific tariff and GNA connectivity framework for offshore wind projects.	New audit framework applicable to offshore wind GENCOs when notified.	Ch.10
CCTS — Sector-Specific Emission Intensity Targets (BEE)	Sector-specific emission intensity targets for power sector under CCTS — will trigger mandatory compliance obligations for large utilities.	Verify when notified — obligated entity designation and GHG inventory baseline.	Ch.13
Draft Mine Closure Rules (MMDR Act)	Specific financial provisioning for mine closure; escrow account maintenance; progressive rehabilitation milestones.	Captive mine GENCOs — track notification; verify provisioning adequacy when enacted.	Ch.9
SEBI ESG / BRSR Core — Extended Scope	Progressively extending mandatory BRSR Core assurance and value chain reporting for listed entities.	Listed power sector entities — assess scope of extended ESG assurance obligations.	Ch.14
Proposed	Mandatory qualifications for	When enacted — verify CIA	Ch.2

Companies Act 2013 Amendment — Internal Audit Provisions	Chief Internal Auditors; standardised Audit Committee reporting format.	qualification compliance and update AC reporting format.	
Proposed Electricity Tariff Policy Amendments	Time-of-day tariffs; cross-subsidy rationalisation; open access simplification.	DISCOM tariff structure and billing audit procedures will require update.	Ch.12
CERC Virtual Power Plant (VPP) Regulations	Regulatory framework for aggregating rooftop solar, small BESS, EV charging as distributed energy resources.	New audit area for DISCOMs and VPP aggregators when notified.	Ch.12
Energy Conservation and Sustainable Building Code (ECSBC) 2024 — Power Sector	Extending ECSBC to operational buildings of power sector entities — additional energy efficiency compliance area.	Include ECSBC compliance in environmental and energy audit checklist when notified.	Ch.14
Green Credit Programme (Green Credit Rules 2023) — sector methodologies pending	Revisions including green credit framework may affect compliance for power projects and mines involving forest land diversion.	Track for captive mine GENCOs and projects with forest land component.	Ch.9; Ch.14

4.6 Technological Developments

SCADA and Energy Management Systems remain central to plant operation and load despatch, and since the CEA Cyber Security Guidelines of 2021 their security has become a material audit area (Chapter 14).

ERP systems raise issues of access control, segregation of duties, master data and the Income Tax Act 2025 TDS payment codes (Section 14.8.1). The RDSS rollout of 250 million smart prepaid meters generates data usable for audit analytics but creates a new Head End System security risk (Sections 12.5 and 14.8.2).

Grid-scale BESS brings new parameters with material financial impact: round-trip efficiency, state of charge and degradation (Section 10.5). AI is used for load forecasting, predictive maintenance, trading and theft detection, and also as an audit tool (Sections 2.9 and 14.8.2).

The digital power platforms relevant to audit are the National Power Portal for CEA data submission (verify accuracy); MERIT for merit-order despatch (DISCOM power purchase audit); URJA MITRA for DISCOM outage data (verify against field records); VIDYUT PRAVAH for power purchase prices (DISCOM trading audit); and the GeM portal, mandatory for central ministries and departments and required of CPSEs under DPE directions (procurement audit, Chapter 14).

4.7 Current Challenges in India's Power Sector

Seven sector-wide challenges shape audit risk:

- ✓ The first is DISCOM financial stress, with accumulated losses, regulatory assets and subsidy dependence, and the ACS-ARR gap as the key metric (Chapter 12).
- ✓ The second is RE integration, where curtailment from grid congestion affects RE developers, DISCOMs and LDCs (Chapters 10–12).
- ✓ The third is coal quality and supply, covering GCV disputes, sampling and grade slippage (Chapter 8).
- ✓ The fourth is cybersecurity: the key systems of power sector entities are notified as Critical Information Infrastructure, and their OT/SCADA systems are exposed (Chapter 14).
- ✓ The fifth is environmental compliance, with repeatedly extended FGD timelines, SO_2 non-compliance and environmental compliance bonds (Chapters 8 and 14).
- ✓ The sixth is land acquisition and clearances, where delays cause cost and IDC overruns (Chapter 14).
- ✓ The seventh is energy transition, where the 500 GW non-fossil target raises Ind AS 36 impairment risk for older thermal units (Chapter 14).

4.8 Power Sector Value Chain — Audit Linkages

The power sector value chain creates interconnected audit risks. A problem at one point in the chain affects multiple entities downstream.

Stage in Value Chain	Key Audit Risk	Downstream Impact
Coal mining (captive mine)	GCV measurement; production reporting; weighbridge fraud	Fuel cost at power plant; tariff billing to DISCOM
Coal supply (CIL/FSA)	ACQ shortfall; GCV disputes; transit loss	Fuel cost; generation availability; capacity charge recovery
Power generation	SHR; APC; PAF; environmental compliance	Energy available for despatch; tariff recovery; regulatory penalties
Transmission	Line losses; ISTS charges; congestion	Power available at state boundary; DISCOM purchase cost
Load despatch	Scheduling accuracy; DSM; SCED	Generator revenue; DISCOM power purchase cost; grid stability
Distribution	AT&C losses; billing accuracy; collection efficiency	DISCOM revenue; consumer service; regulatory compliance
Trading and exchange	Prudency of purchase; price discovery; settlement accuracy	DISCOM power purchase cost; tariff pass-through to consumers
End consumer	Billing accuracy; collection; theft	DISCOM revenue realisation; AT&C loss computation

4.9 Power Sector Ownership Structure

Understanding the ownership category of an entity is the first step in scoping an internal audit — it determines the applicable governance framework, oversight bodies, and referral documents from Section 1.4. Refer Chapter 6 for detailed entity profiles.

Category	Examples	Additional Governance Frameworks

Central Public Sector Undertakings (CPSUs)	NTPC; NHPC; PGCIL; SECI; NLC India	DPE Corporate Governance Guidelines for CPSEs; CVC guidelines; CAG supplementary audit; Parliamentary oversight; SEBI LODR (if listed)
State Public Sector Undertakings (State PSUs)	TGGENCO; MPPGCL; MAHAGENCO; state DISCOMs; STUs	State Government governance directives; State Accountant General audit; state legislature committee oversight; frameworks vary across states
Private Sector Entities	Adani Power; Tata Power; Torrent Power; JSW Energy	Companies Act 2013 governance requirements; SEBI LODR (if listed); not subject to CAG audit; CERC/SERC regulatory oversight applies
Joint Ventures	CPSU–State Government JVs; CPSU–Private JVs	A JV in which Central or State Government companies together hold 51% or more is itself a Government company and subject to CAG audit; otherwise the Companies Act and the shareholder agreement govern; review JV-specific shareholder agreement provisions in all cases

4.10 Payment Flow and Financial Structure

The power sector has a connected payment chain: the consumer pays the DISCOM; the DISCOM pays the GENCO (capacity and energy charges under the PPA) and the transmission licensee (transmission charges); and the GENCO pays the coal company under the FSA or, for a captive mine, the MDO. Each link carries timing risk and leakage risk. The most significant structural stress arises at the DISCOM level — the persistent ACS-ARR gap from inadequate tariff revision, subsidy obligations, and AT&C losses. When DISCOMs delay payment to GENCOs, working capital stress cascades through the entire chain. Internal auditors at each level must understand the financial health of upstream and downstream entities. Refer Chapters 8, 12, and 14.

4.11 Tariff Determination — Overview for Internal Auditors

The tariff determination process is central to power sector audit. The following is a brief orientation whereas detailed audit procedures are covered in Chapters 8 and 12.

For generating companies whose tariff is determined under Section 62 of the Electricity Act 2003, the entity files a tariff petition setting out its capital cost and annual fixed charges; the regulator conducts a prudency check, examining whether costs were necessarily and prudently incurred, and issues a tariff order specifying capacity and energy charges; actual costs and performance are then compared with the tariff order in a true-up petition, and differences are adjusted in future tariff.

The prudency check is the most significant regulatory audit to which a power sector entity is subjected. Costs that are disallowed as imprudent cannot be recovered from consumers. Internal audit therefore plays a critical role in pre-petition review ensuring all costs claimed are accurately stated, properly documented, and defensible under prudency scrutiny.

For generating companies under Section 63 — competitive bidding — tariff is fixed at the bid price for the duration of the PPA. There is no prudency check or true-up, apart from change-in-law and other adjustments provided in the PPA. Cost overruns are borne by the developer. This fundamentally changes the internal audit focus from tariff recovery to cost efficiency and PPA compliance. Refer Section 7.7.

4.12 Project Development Lifecycle — Navigation Guide

For internal auditors involved in capital works audit, the following table maps the key stages of power project development to the relevant chapter for audit guidance.

Stage	Key Activities	Primary Audit Concern	Refer
1. Feasibility and DPR	Techno-economic feasibility; Detailed Project Report	Cost estimation accuracy; DPR approval process	Ch.14
2. Statutory Clearances	Environmental Clearance; Forest Clearance	Compliance with clearance conditions; timeline tracking	Ch.14
3. Land Acquisition and R&R	Land acquisition under RFCTLARR; R&R implementation	Fair compensation; R&R entitlement delivery	Ch.14
4. Financial Closure	Lender due diligence; Loan agreements	Loan covenant compliance; DSRA; DSCR	Ch.14
5. Construction	Civil; mechanical; electrical works	Capital cost prudency; contractor performance	Ch.14
6. Commissioning	Trial runs; IBR certificates; CEA inspection; COD	Premature or delayed COD; capitalisation timing	Ch.8
7. Tariff Petition	Tariff petition filing; prudency check; auditor certificate	Data accuracy; CERC prudency compliance	Ch.8
8. Operations	Ongoing generation; tariff billing; regulatory compliance	KPI vs. norms; environmental compliance	Ch.8–13
9. Asset Life Management	R&M; life extension; decommissioning	Impairment; stranded asset risk; decommissioning provisioning	Ch.14

4.13 Grid Operation Basics — For Internal Auditors

A basic understanding of grid operation helps internal auditors auditing GENCOs, TRANSCOs, and LDCs evaluate management explanations and assess scheduling-related audit findings. Detailed audit procedures are covered in Chapter 11.

Scheduling: Each day, generating stations submit their declared capacity to the RLDC/SLDC. The LDC prepares a schedule allocating generation to each station based on merit order, transmission constraints, and demand forecast. The schedule determines how much each station is expected to generate in each 15-minute time block.

Deviation and DSM: If a generator produces more or less than its scheduled quantity, the difference is settled through the Deviation Settlement Mechanism at rates linked to the market clearing price under the CERC DSM Regulations. Auditors should verify DSM charge computations and reconcile with scheduling records from RLDC/SLDC.

ABT and Capacity Charges: Under Availability Based Tariff, a thermal GENCO receives capacity charges based on its declared availability, not on actual generation. A plant that is available but not called upon to generate still receives its fixed costs. Auditors should verify that declared availability is supported by actual plant condition records.

SCED: The Security Constrained Economic Despatch mechanism operated by NLDC dispatches generating stations in merit order i.e. cheapest first subject to transmission constraints. Understanding these concepts helps auditors evaluate whether management explanations such as "grid backed down our plant" or "SCED restricted our generation" are credible and supported by documentary evidence from RLDC/SLDC.

4.14 Expert Committee Reports and Due Diligence Reports — Relevance to Internal Audit

Power sector entities, particularly public sector undertakings, generate or commission a range of independent reports like expert committee reports constituted by Boards or managements to examine specific operational or procurement issues; Parliamentary Standing Committee, COPU and PAC reports examining PSU governance and efficiency; lender due diligence reports covering technical, financial, legal, and environmental risks prepared at the time of project financing; and Independent Engineer reports periodically assessing project progress and operational performance for lenders. These reports contain authoritative independent assessments that are highly valuable for internal audit yet are rarely used systematically.

Internal auditors should obtain copies of all such reports relevant to the audit period, verify that recommendations have been implemented within stipulated timelines, and use the findings as intelligence for risk assessment and audit programme design. Significant divergence between an independent assessor's findings and management's own representations is a red flag requiring investigation. Access to lender due diligence and independent engineer reports should be sought through the CIA with Audit Committee backing where required, as some reports may be commercially sensitive.

5. LEGAL AND REGULATORY FRAMEWORK — COMPLETE MATRIX

5.0 Introduction

The power sector in India operates within one of the most extensive legal and regulatory frameworks of any industry. An internal auditor who is not familiar with this framework cannot effectively evaluate compliance, assess risk, or interpret management explanations. A regulatory non-compliance in the power sector is not merely a legal issue; it can result in tariff disallowance, plant shutdown, prosecution, financial penalty, or loss of licence. The stakes are therefore high.

This chapter provides a comprehensive matrix of laws, regulations, rules, and policy frameworks applicable to power sector entities covering both legislation that has been in force since before the Second Edition and remains applicable, and legislation enacted or significantly amended since the Second Edition. It is organised by subject matter: electricity laws; coal and mining laws; environmental laws; company and financial laws; direct and indirect tax laws; labour laws; transport laws; IT and cyber laws; and other applicable laws.

For each applicable law or regulation, this chapter identifies what it covers; which entities it applies to; and the key audit implications. Detailed audit procedures for each area are covered in the entity-specific chapters like Chapters 8 through 14. This chapter is the reference matrix; those chapters are the execution framework.

Auditors should note that state-specific regulations like SERC tariff orders; state grid codes; state RPO trajectories; state pollution control board consents; and state labour notifications are equally applicable and must be supplemented by the auditor based on the state in which the entity operates. These cannot be listed exhaustively here given their volume and state-specific nature. Refer Appendix 8 for details.

Note on Normative Benchmarks: The normative parameters cited in this Guidance Note such as PAF, SHR, APC, SOC and O&M norms for GENCOs; availability norms for TRANSCOs; AT&C, collection efficiency and loss norms for DISCOMs; CUF and PR for RE GENCOs; system operation charge norms for LDCs; production, strip ratio and GCV targets for captive mines; and SO_2, NO_x, particulate and water consumption norms for thermal plants — are illustrative figures used to explain audit procedures and compute financial impact. The norm that applies to an entity is the one in its applicable CERC or SERC tariff order, MYT order, MoEFCC notification (which varies by plant vintage), PPA or approved mine plan for the relevant period, and auditors must verify it from that source before computing variances or financial impact.

5.1 Electricity Laws

5.1.1 Electricity Act 2003 (Act No. 36 of 2003)

Coverage: The principal legislation governing India's entire power sector. Provides for de-licensed generation; licensing of transmission, distribution and trading; establishment of CERC and SERCs; open access; tariff regulation; consumer protection; and penalties for offences.
Applicable to: All power sector entities like GENCOs, TRANSCOs, DISCOMs, LDCs, traders, exchanges.
Key provisions for internal audit:

Section	Provision	Audit Implication

Section	Provision	Audit Implication
Sections 7–8	Generation — no licence required; hydro schemes need CEA concurrence under Section 8	Verify CEA concurrence for hydro schemes; compliance with CEA technical and connectivity standards
Section 14	Transmission; distribution; trading licence	Verify licence validity; conditions compliance; renewal
Section 26-33	Load despatch — NLDC, RLDCs and SLDCs	LDC compliance with scheduling; grid code; system operation charges
Section 38-42	Transmission and distribution — open access	Open access charges; cross-subsidy surcharge; wheeling charges
Section 42(6)	Electricity Ombudsman	DISCOM compliance with Ombudsman orders; 30-day implementation
Section 61-65	Tariff — principles; determination; Section 62 and 63	Tariff petition accuracy; prudency compliance; Section 63 PPA compliance
Section 79	CERC functions — inter-state tariff; trading	CERC regulation compliance
Section 86	SERC functions — state tariff; RPO	SERC order compliance; RPO tracking
Section 86(1)(b)	SERC regulation of DISCOM power purchase and procurement (PPAs)	PPA terms compliance; payment security
Section 126	Assessment for unauthorised use	Anti-theft operations; revenue protection
Section 135-140	Theft of electricity and related offences	Theft cases — registration; recovery; court tracking

5.1.2 Electricity (Amendment) Rules 2023

Coverage: Ministry of Power Notification G.S.R. 466(E) dated 30 June 2023, amending the Electricity Rules, 2005. It amends Rule 3 on captive generating plants, including affiliate-company ownership and captive consumption through Energy Storage Systems/subsidiaries, and Rule 19 on Uniform Renewable Energy Tariff for the central pool.

Applicable to: Power-sector entities, particularly captive generating plants and entities covered by the Uniform Renewable Energy Tariff framework.

Key audit implications: Verify compliance with Rule 3 ownership and annual captive-consumption requirements, including the 51% consumption criterion, from relevant generation and metering records. For applicable entities, verify compliance with Rule 19 requirements, as amended from time to time. Refer Sections 7.4 and 7.5.

5.1.3 Electricity Rules 2005

Coverage: Rules framed under the Electricity Act 2003 covering captive generating plants (Rule 3), the obligations of distribution licensees, and other matters under the Act.

Applicable to: Captive generating plants; distribution licensees.

Key audit implications: Captive status under Rule 3 (see Section 5.1.2 and Chapter 7); licensee compliance with the Rules. Standards of performance are covered in Section 5.1.4.

5.1.4 Electricity (Rights of Consumers) Rules, 2020 (as amended up to 2024)

Coverage: Rules providing specific rights to electricity consumers like guaranteed standards of performance; compensation for non-compliance; grievance redressal through CGRF and Electricity Ombudsman; and billing accuracy standards.

Applicable to: All distribution licensees (DISCOMs).
Key audit implications: Verify CGRF constitution and meeting frequency; complaint disposal rate within 45 days; Electricity Ombudsman order implementation within 30 days; consumer compensation payments. Refer Chapter 12.

5.1.5 Indian Electricity Grid Code (IEGC) 2023

Coverage: Issued by CERC under Section 79(1)(h) and in force from 1 October 2023. Governs the operation and maintenance of the inter-state transmission system; connectivity conditions; scheduling and despatch; and grid security.

Applicable to: All entities connected to ISTS like GENCOs, TRANSCOs, DISCOMs, LDCs.
Key audit implications: Verify scheduling accuracy; grid code compliance; outage coordination; frequency maintenance; deviation settlement. Refer Chapter 11.

5.2 CERC Regulations — Current Framework

5.2.1 CERC (Terms and Conditions of Tariff) Regulations 2024-29

Coverage: Determines norms and methodology for tariff determination for central generating stations and inter-state transmission systems for the Control Period 2024-29 (1 April 2024 to 31 March 2029). Replaces CERC Tariff Regulations 2019-24.
Applicable to: Central GENCOs and inter-state TRANSCOs under CERC jurisdiction.
Key parameters for internal audit:

Parameter	CERC 2024-29 Norm (Indicative)	Audit Implication
Plant Availability Factor (PAF) — Thermal	85%	Monthly tracking; forced outage analysis; capacity charge impact
Station Heat Rate (SHR) — 500 MW supercritical	2340 Kcal/kWh	Monthly SHR monitoring; variance computation; excess coal cost
Specific Oil Consumption (SOC)	0.30 ml/kWh	Oil log reconciliation; oil tank calibration; monthly CERC reporting
APC — Supercritical units	As per unit-specific norms	Sub-component tracking; comparison with norm
O&M Norms per MW	Inflation-indexed (revised upward)	Cost centre O&M tracking; variance analysis
Return on Equity (ROE)	15.5% (tax grossing revised)	Equity computation; tax impact on ROE
Working Capital — Receivables	45 days	Receivable aging; payment security adequacy
Days of stock as per CEA norm (by distance from mine)	Days as per CEA norm	Physical stock vs. book reconciliation
Capital Spares (Initial)	4% of capital cost	Capitalisation vs. revenue classification

Parameter	CERC 2024-29 Norm (Indicative)	Audit Implication
FGD O&M	New norm introduced	FGD cost centre; lime/gypsum tracking
Depreciation	As per schedule	Asset-wise depreciation computation

Note: CERC Tariff Regulations 2019-24 remain relevant for true-up petitions covering periods up to 31 March 2024. Internal auditors working on legacy true-up audits should refer to the applicable control period norms.

5.2.2 CERC RE Tariff Regulations 2024-27

Coverage: Determines methodology and norms for tariff of renewable energy projects like solar PV, wind, biomass, small hydro, and hybrid for the period 2024-27.
Applicable to: RE GENCOs filing tariff petitions with CERC.
Key audit implications: Verify CUF norms; O&M norms; capital cost benchmarks; deemed generation provisions; ISTS waiver status. Refer Chapter 10.

5.2.3 CERC (Connectivity and General Network Access to ISTS) Regulations 2022

Coverage: Introduces General Network Access (GNA) as the unified framework for ISTS connectivity. Refer Section 3.3 for the GNA definition.
Applicable to: All generators, distribution licensees, and bulk consumers seeking ISTS connectivity.
Key audit implications: Verify GNA application status; queue position; connectivity charges; deemed connectivity timeline; transition from LTA to GNA for existing projects. Refer Chapter 11.

5.2.4 Inter-State Open Access — Temporary GNA (T-GNA)

Coverage: Short-term access to ISTS is now granted as T-GNA under the CERC GNA Regulations 2022, which replaced the CERC Open Access Regulations 2008.
Applicable to: Open access customers; power traders; captive plants drawing from ISTS.
Key audit implications: Verify T-GNA applications and charges; scheduling compliance; legacy short-term open access settlements before the switch-over; state-level cross-subsidy and additional surcharges under SERC regulations. Refer Chapters 11 and 12.

5.2.5 CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations 2020

Coverage: Governs the sharing of ISTS charges and losses among designated ISTS customers through national, regional, transformer-level and AC usage-based components, replacing the earlier Point of Connection (PoC) method.
Applicable to: All designated ISTS customers — DISCOMs, generators with GNA, bulk consumers.
Key audit implications: Verify monthly ISTS bills raised by CTU against the CERC methodology; reconcile with Grid-India computations; RE waiver application; impact on tariff filing. Refer Chapter 11.

5.2.6 CERC (Power Market) Regulations 2021

Coverage: Governs the power market in India including power exchanges, trading, and market participants.
Applicable to: Power exchanges (IEX, PXIL and HPX); power traders; market participants.

Key audit implications: Verify exchange membership compliance; trading limits; settlement; position limits; market coupling compliance. Refer Chapter 13.

5.2.7 CERC (Deviation Settlement Mechanism) Regulations 2024

Coverage: Governs settlement of deviations by regional entities from their schedules, with deviation charges linked to market clearing prices. Replaced the earlier UI mechanism.
Applicable to: All regional entities — generating stations, states/DISCOMs and bulk consumers.
Key audit implications: Verify DSM charge computation; reconciliation of DSM payments and receipts with RLDC/SLDC; accounting treatment of DSM charges. Refer Chapter 11.

5.2.8 CERC (Ancillary Services) Regulations 2022

Coverage: Governs the provision and procurement of Secondary Reserve Ancillary Services (SRAS) and Tertiary Reserve Ancillary Services (TRAS); primary response is a mandatory IEGC obligation.
Applicable to: Generating stations providing ancillary services; NLDC/RLDCs procuring ancillary services.
Key audit implications: Verify ancillary service availability; performance monitoring; charge recovery by LDCs; payment to providing generators. Refer Chapter 11.

5.2.9 Ministry of Power Order on RPO and Energy Storage Obligation — 22 July 2022

Coverage: MoP Order dated 22 July 2022, read with the corrigendum of 19 September 2022. It sets the RPO and ESO trajectory up to FY 2029-30 for distribution licensees, open access consumers and captive plants. ESO starts at 1% in FY 2023-24 and rises to 4% by FY 2029-30.
Applicable to: Distribution licensees; open access consumers; captive generating plants as obligated entities.
Key audit implications: Verify ESO compliance percentage tracked separately from RPO; BESS or PSP procurement for ESO compliance; performance monitoring of BESS — RTE; SoC; degradation. Refer Chapter 10.

5.2.10 CERC (Terms and Conditions for Purchase and Sale of Carbon Credit Certificates) Regulations 2026

Coverage: CERC notified the CERC (Terms and Conditions for Purchase and Sale of Carbon Credit Certificates) Regulations 2026 on 27 February 2026, providing the detailed trading framework for Carbon Credit Certificates (CCCs) on power exchanges. These Regulations operationalise CCC trading under the Carbon Credit Trading Scheme 2023 notified by the Ministry of Power.
Applicable to: Entities in sectors notified under the compliance mechanism (power sector targets pending); project developers under the offset mechanism.
Key audit implications: Verify GHG inventory accuracy; MRV plan compliance; National Carbon Registry registration; carbon credit issuance; trading on power exchanges under CERC CCC Regulations 2026; carbon credit accounting in books. Refer Chapters 13 and 14.

5.3 SERC and JERC Framework

5.3.1 State Electricity Regulatory Commissions (SERCs)

Coverage: Each state has its own SERC constituted under Section 82 of the Electricity Act 2003. SERCs determine retail tariff; regulate distribution and intra-state transmission; set RPO targets; issue state grid codes; and govern consumer protection at the state level.

Applicable to: State GENCOs; STUs; DISCOMs; state-level open access consumers; captive plants in the state.

Key audit implications for state power utilities: Annual Revenue Requirement (ARR) filing — accuracy of data submitted; timely filing; Tariff Order compliance — implementation of approved tariff schedule; category-wise tariff; time-of-day tariffs where applicable; Multi-Year Tariff (MYT) order compliance — performance against milestones; annual true-up; RPO targets — solar; wind; hydro; total RE — state-wise targets set by SERC; compliance verification; REC trading; Open Access Regulations — intra-state charges; cross-subsidy surcharge computation; Net Metering / Gross Metering Regulations — prosumer framework; bidirectional metering; settlement; Consumer Grievance Redressal Forum (CGRF) — constitution; meeting frequency; disposal rate; State Grid Code compliance — intra-state scheduling; outage coordination with SLDC; SLDC interface — scheduling accuracy; system operation charges approval and recovery.

Note: SERC orders and regulations vary significantly across states. Auditors must obtain and review the specific SERC order applicable to the entity being audited for the audit period.

5.3.2 Joint Electricity Regulatory Commissions (JERCs)

JERCs are constituted for Union Territories and for states that do not have their own SERC. For audit purposes, JERC orders carry the same authority and create the same compliance obligations as SERC orders.

5.3.3 RPO Trajectory and Hydro Purchase Obligation

Coverage: The Ministry of Power Order of 22 July 2022 sets the national RPO trajectory to FY 2029-30, comprising wind, hydro (HPO), distributed RE and other RE components; SERCs specify state RPO targets in line with it.

Applicable to: All distribution licensees; open access consumers; captive plants.

Key audit implications: Verify monthly RPO computation; actual RE purchase against target; REC procurement for shortfall; HPO compliance separately tracked; penalty provisions for non-compliance; annual RPO compliance certificate filing with SERC. Refer Chapter 12.

5.4 CEA Standards and Regulations

5.4.1 CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022

Coverage: Prescribes technical standards for construction of electrical plants and electric lines — voltage levels; insulation; clearances; safety; and cybersecurity provisions for automation and control systems. These Regulations supersede the earlier CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2010.

Applicable to: All generating companies; transmission licensees; distribution licensees.

Key audit implications: Verify CEA approval for construction; compliance with technical standards; inspection certificates. Refer Sections 8.6, 11.4 and 14.5.

5.4.2 CEA (Technical Standards for Connectivity to the Grid) Regulations 2007

Coverage: Prescribes technical standards for connectivity of generating stations, energy storage systems, and distribution systems to the grid — protection coordination; interface metering; fault level; reactive power. These are technical standards at the connection point.

Applicable to: All entities seeking connectivity to ISTS or state transmission system.

Key audit implications: Verify connectivity compliance; protection coordination; metering standards at connection point. Refer Chapter 11.

5.4.3 CEA (Installation and Operation of Meters) Regulations 2006 (as amended up to 2022)

Coverage: Prescribes accuracy class; installation standards; sealing; calibration; and testing requirements for energy meters at generating stations; transmission; and distribution level.
Applicable to: All power sector entities.
Key audit implications: Verify meter calibration records; accuracy class compliance; meter sealing; last testing date; CEA-prescribed testing frequency; calibration by accredited laboratory. Refer Chapters 8 and 12.

5.4.4 CEA (Measures Relating to Safety and Electric Supply) Regulations 2023

Coverage: Prescribes safety measures for electrical installations; construction and maintenance of electrical lines; and reporting of electrical accidents.
Applicable to: All power sector entities with electrical installations.
Key audit implications: Verify electrical accident reporting to CEA within 24 hours; compliance with safety regulations; annual safety inspection records.

5.4.5 CEA (Grid Standards) Regulations 2010

Coverage: Issued by CEA under the Electricity Act 2003. Prescribes voltage; frequency; and power factor standards to be maintained by all entities connected to the grid.
Applicable to: All generating stations; transmission and distribution licensees.
Key audit implications: Verify frequency band compliance (49.9-50.05 Hz); voltage profile; power factor — reactive power compensation adequacy. For operational scheduling compliance under the IEGC, refer Section 5.1.5. Refer Chapter 11.

5.4.6 Imported Power Equipment — MoP Orders 2020–21

Coverage: Prior permission for import of specified power supply and system equipment from 'prior reference' countries, and testing of imported equipment in designated Indian laboratories.
Applicable to: GENCOs and TRANSCOs importing electrical equipment.
Key audit implications: Verify permission obtained before import where required; test certificates from designated laboratories; compliance with CEA technical specifications.

5.5 National Policy Framework

5.5.1 National Tariff Policy 2016

Coverage: Issued under Section 3 of the Electricity Act 2003 on 28 January 2016. Provides guidance to CERC and SERCs on tariff determination principles; RPO obligations; ISTS charge waiver for RE; open access simplification; must-run status for RE; and cross-subsidy reduction trajectory.
Applicable to: CERC; SERCs; all regulated entities.
Key audit implications: Verify SERC tariff orders are consistent with NTP principles; RPO compliance; must-run status implementation for RE plants; ISTS charge waiver eligibility for RE projects. Refer Chapters 10 and 12.

5.5.2 National Electricity Plan 2022-32

Coverage: The National Electricity Plan 2022-32 is a medium and long-term capacity addition and transmission planning document prepared by CEA under Section 3(4) of the Electricity Act 2003,

covering capacity addition, transmission, fuel linkage and RE integration up to 2032. It is distinct from the National Electricity Policy notified on 12 February 2005 under Section 3, which remains the operative policy.

Applicable to: All power sector entities — provides context for capacity addition plans.

Key audit implications: Internal auditors should use NEP 2022-32 targets as context when evaluating capital works plans and capacity addition projects. Deviation from NEP-projected timelines may indicate project delays requiring audit attention.

5.6 Coal and Mining Laws

5.6.1 Occupational Safety, Health and Working Conditions Code, 2020 — Mine Safety Framework

Coverage: The principal labour-safety framework applicable to mines, effective from 21 November 2025, subsuming the Mines Act, 1952. Mine-safety administration is undertaken by the Directorate General of Mines Safety (DGMS) under the Ministry of Labour and Employment, read with the Coal Mines Regulations, 2017 and other applicable rules and regulations as continued or amended under the transitional framework. Obligations for periods before 21 November 2025 continue to be tested under the Mines Act, 1952.

Applicable to: GENCOs operating captive coal mines.

Key audit implications: Mine Manager's competency certificate — valid certificate required; DGMS approval; Statutory examinations — quarterly; half-yearly; annual inspections by mine officials; DGMS inspection reports — compliance with observations within specified timelines; Accident and dangerous-occurrence reporting — loss of life, serious bodily injury and specified dangerous occurrences to be reported forthwith to the Regional Inspector, followed by prescribed notice within 24 hours in accordance with Regulation 8 of the Coal Mines Regulations, 2017; Safety Officer appointment — qualifications; DGMS approval; Working hours; rest days; overtime — shift roster compliance; Prosecution register — cases filed against officials; court dates; outcomes. Refer Chapter 9.

5.6.2 Mines and Minerals (Development and Regulation) Act 1957 (MMDR Act)

Coverage: Governs grant of mining leases; royalty on minerals; District Mineral Foundation; National Mineral Exploration Trust; and progressive mine closure.

Applicable to: GENCOs operating captive coal mines.

Key audit implications: Mining lease — validity; conditions compliance; area compliance; Royalty on coal — monthly payment to State Government; computation per notified rates; Coal Dispatch Annual Return reconciliation; DMF contribution — 10% of royalty for mines allotted on or after 12 January 2015; 30% for earlier mines; utilisation tracking; NMET contribution — 3% of royalty; deposit to national trust; mine plan compliance; Progressive Mine Closure Plan — MoC approval; annual provisioning; escrow account maintenance. Refer Chapter 9.

5.6.3 Coal Mines (Special Provisions) Act 2015

Coverage: Enabled fresh allocation of coal blocks after the Supreme Court's 2014 order cancelling earlier allocations. Schedule I lists all cancelled blocks; Schedule II (blocks in or near production) and Schedule III (blocks for specified end-uses) are subsets. Blocks are allocated either by auction (Section 4) or by allotment to government companies (Section 5).

Applicable to: GENCOs with coal blocks allotted under this Act.

Key audit implications: Allotment compliance — conditions of allotment; end-use restriction to power generation; Revenue share or reserve price and additional premium — per the auction or allotment terms; Performance parameters — production targets; penalty for shortfall; Monitoring committee — quarterly meetings; compliance reporting; Transfer restrictions — captive mine cannot be transferred without government approval. Refer Chapter 9.

5.6.4 Coal Mines Regulations 2017

Coverage: Detailed regulations governing safety management; environmental management; mine closure; and operational requirements of coal mines.
Applicable to: GENCOs operating captive coal mines.

Key audit implications: Safety Management Plan (SMP) — Board approval; annual review; compliance audit; Environmental Management Plan (EMP) — alignment with EC conditions; implementation; Mine closure plan — approved; annual financial provisioning; VHF communication system — underground connectivity; emergency response; Self-Contained Self-Rescuer (SCSR) — availability per person underground; inspection records; Methane monitoring — CH_4 levels; ventilation audit; Explosives management — PESO licence; magazine safety; consumption vs. blasting records. Refer Chapter 9.

5.6.5 Coal Mine Allotment/Auction Payments — Coal Mines (Special Provisions) Act 2015 and Rules 2014

Coverage: Prescribes financial obligations arising from allocation/auction of coal mines, including upfront amount, reserve/final price or revenue share, as applicable under the relevant allocation methodology and allotment/auction documents.
Applicable to: GENCOs operating coal mines allotted or auctioned under the applicable coal-allocation framework.

Key audit implications: Verify applicable reserve/final price or revenue share, annual escalation/ adjustment where prescribed, payment to the appropriate Government, and reconciliation with coal production/dispatch and the terms of the allotment or vesting order. Refer Chapter 9.

5.6.6 DGMS Regulations and Circulars

Coverage: DGMS issues standing orders, circulars and technical circulars supplementing the OSH Code 2020 (which subsumes the Mines Act, 1952) and the Coal Mines Regulations, 2017 on specific safety matters.
Applicable to: GENCOs operating captive coal mines.
Key audit implications: Maintain register of applicable DGMS circulars; verify compliance with each; track inspection findings and compliance timelines. Refer Chapter 9.

5.6.7 Ministry of Coal Guidelines on Mine Planning and Closure

Coverage: The Ministry of Coal issues guidelines on mine planning; production targets; mineral conservation; mine safety; and progressive mine closure for captive coal blocks under the Coal Mines (Special Provisions) Act 2015 and MMDR Act 1957. The Coal Controller's Organisation (CCO) under the Ministry of Coal monitors coal production and dispatch data and administers coal dispatch returns.
Applicable to: GENCOs operating captive coal mines.
Key audit implications: Verify MoC-approved mine plan; actual production vs. approved plan; OB:Coal ratio compliance; return filing; progressive mine closure compliance. Refer Chapter 9.

5.7 Environmental Laws

5.7.1 Environment (Protection) Act 1986 and Rules 1986

Coverage: Umbrella environmental legislation under which Environmental Clearance (EC) is granted for power projects and mines and environmental standards are prescribed by MoEFCC.
Applicable to: All power plants and captive mines, as applicable.
Key audit implications: Environmental Clearance — validity and compliance with conditions; half-yearly EC compliance reports; thermal power plant environmental standards — PM, SO_2, NO_x, mercury and water-consumption norms, as applicable; compliance with prescribed emission-control requirements and timelines; environmental compensation/other consequences for non-compliance, where applicable; accuracy and completeness of environmental compliance reporting. Refer Appendix A2.2.

5.7.2 Air (Prevention and Control of Pollution) Act 1981

Coverage: Governs prevention and control of air pollution. Administered by CPCB and SPCBs.
Applicable to: All thermal power plants; all captive mines.
Key audit implications: Consent to Establish (CTE) and Consent to Operate (CTO) from SPCB — validity; renewal; conditions; Stack emission compliance — quarterly stack testing by MoEFCC-approved laboratory; CEMS installation and operation — OCEMS portal connectivity; data validity; calibration; CPCB/SPCB show cause notices — compliance within stipulated timeline; Ambient Air Quality Monitoring (AAQM) — continuous monitoring; CAAQMS portal data. Refer Chapters 8 and 14.

5.7.3 Water (Prevention and Control of Pollution) Act 1974

Coverage: Governs prevention and control of water pollution and regulation of effluent discharge through the SPCB consent mechanism.
Applicable to: All power plants and captive mines, as applicable.
Key audit implications: SPCB consent conditions — validity, effluent quality and discharge compliance; ETP — operational status and monitoring; ZLD compliance, where applicable; water consumption — actual versus applicable MoEFCC norms; State water allocation/charges — quantity drawn versus permitted quantity and payment to the competent State authority, where applicable; mine-water treatment and discharge compliance. Refer Chapters 8 and 9.

5.7.4 Van (Sanrakshan Evam Samvardhan) Adhiniyam 1980 (formerly Forest (Conservation) Act 1980)

Coverage: Governs diversion of forest land for non-forest purposes including power plants; transmission lines; and coal mines. The 2023 amendment renamed the Act and revised the scope of land to which it applies.
Applicable to: GENCOs; TRANSCOs; mine operators — wherever projects involve forest land.
Key audit implications: Stage I and Stage II Forest Clearance (FC) — compliance with FC conditions; compensatory afforestation; NPV (Net Present Value) payment; Compensatory Afforestation — actual plantation vs. required; third-party verification; FC conditions compliance — compliance reports; violations; penalty orders; Green credit provisions under 2023 amendment — eligibility assessment. Refer Chapters 9 and 10.

5.7.5 Dam Safety Act 2021

Coverage: Provides for surveillance; inspection; operation; and maintenance of dams. Establishes National Dam Safety Authority and State Dam Safety Organisations.
Applicable to: GENCOs operating hydropower projects with dams; PSPs.
Key audit implications: Dam Safety Unit — constitution; annual pre- and post-monsoon inspections and reports to the State Dam Safety Organisation; Comprehensive dam safety evaluation by an independent panel of experts — conducted at the prescribed interval; implementation of recommendations; Emergency Action Plan (EAP) — adequacy; mock drill records; Dam safety monitoring — instrumentation; seepage monitoring; displacement monitoring; Rehabilitation of old dams — compliance with inspection recommendations. Refer Chapter 10.

5.7.6 Hazardous and Other Wastes Rules 2016, Fly Ash Notification 2021 and Battery Waste Management Rules 2022

Coverage: The Hazardous Waste Rules govern handling, storage and disposal of hazardous wastes such as used transformer and lubricating oil; fly ash utilisation is governed separately by the MoEFCC Fly Ash Notification of 31 December 2021; and battery disposal by the Battery Waste Management Rules 2022.

Applicable to: All thermal power plants; BESS operators; all entities with transformers.

Key audit implications: SPCB authorisation and manifest records for used oil and other hazardous waste; 100% fly ash utilisation within the notified compliance cycle, legacy ash targets and environmental compensation for shortfall; utilisation reporting on the CPCB portal; FGD gypsum sale or disposal records; battery disposal through registered recyclers and EPR compliance.

5.7.7 E-Waste (Management) Rules 2022

Coverage: Governs management of electrical and electronic waste, applicable to IT equipment; smart meters; control systems.
Applicable to: All power sector entities.
Key audit implications: Verify e-waste disposal through authorised recyclers; Extended Producer Responsibility (EPR) compliance; disposal records.

5.7.8 Energy Conservation Act 2001 (as amended 2022)

Coverage: Governs energy efficiency; the PAT scheme; and through the 2022 amendment — the Carbon Credit Trading Scheme and Green Hydrogen obligations.
Applicable to: Designated Consumers (DCs) — power plants above 30,000 toe per annum; all entities for CCTS.
Key audit implications: DC registration with BEE — threshold and registration compliance; PAT Scheme — applicable PAT cycle, energy-performance baseline/target, M&V and BEE verification; ESCert entitlement/obligation and trading; compliance with applicable PAT-cycle requirements. PAT Cycle VII covers FY 2022-23 to FY 2024-25; PAT Cycle VIII covers FY 2023-24 to FY 2025-26 for the Designated Consumers/sectors notified thereunder. CCTS — GHG inventory, registration, MRV and carbon-credit compliance, as applicable. Refer Chapter 13.

5.7.9 Carbon Credit Trading Scheme 2023 (Ministry of Power)

Coverage: Notified by MoP vide S.O. 2825(E) dated 28 June 2023 under Section 14AA of the Energy Conservation Act 2001 (as amended in 2022). BEE is the administrator; Grid-India operates

the National Carbon Registry; and CERC regulates trading of Carbon Credit Certificates on power exchanges under the CERC CCC Regulations 2026.

Applicable to: Entities in sectors notified under the compliance mechanism (power sector targets pending); project developers under the offset mechanism.

Key audit implications: GHG inventory preparation; accredited validator/verifier engagement; MRV plan compliance; carbon credit issuance; trading on power exchanges under CERC CCC Regulations 2026; carbon credit accounting in books. Refer Chapters 13 and 14.

5.8 Company and Financial Laws

5.8.1 Companies Act 2013

Coverage: Governs corporate governance; financial reporting; audit; related party transactions; CSR; Board and Audit Committee requirements; and statutory compliance.

Applicable to: All power sector entities incorporated as companies.

Key provisions for internal audit:

Section	Provision	Audit Implication
Section 138	Internal Audit — appointment; scope	Basis for internal audit; CMA eligibility; refer Chapter 2
Section 134	Board's Report	Financial statement accuracy; internal control statement
Section 135	CSR — 2% of average net profit	CSR policy; eligible activities; implementation; unspent amount
Section 143(6)	CAG supplementary audit	Cooperation with CAG; ATN tracking; refer Chapter 14
Section 148	Cost Audit	Cost auditor appointment; CRA-2; CRA-3; cost records
Section 177	Audit Committee	Constitution; functions; internal audit reporting; RPT approval
Section 188	Related Party Transactions	RPT approval process; arm's length pricing; Board/shareholder approval
Section 185-186	Loans; investments; guarantees	Board approval; limits; compliance

CARO 2020 — Key paragraphs for power sector:

CARO 2020 Para	Coverage	Power Sector Implication
Para 3(i)	Fixed assets physical verification	Large generating assets; land records; PPE reconciliation
Para 3(ii)	Inventory physical verification	Coal stock; stores inventory; physical vs. book
Para 3(vi)	Cost records maintenance	Cost audit applicability; CRA-1 format compliance
Para 3(vii)	Statutory dues	TDS; GST; PF; ESI; disputed dues
Para 3(xi)	Fraud	Nature and amount; management response
Para 3(xiv)	Internal audit system	Whether commensurate with size and business; whether internal audit reports were considered by the statutory auditor

CARO 2020 Para	Coverage	Power Sector Implication
Para 3(xvii)	Cash losses	Significant for loss-making DISCOMs; disclosure

5.8.2 Companies (Cost Records and Audit) Rules 2014

Coverage: Specifies classes of companies required to maintain cost records and get them audited. Electricity generation is a specified product/service.
Applicable to: Power sector companies with overall turnover above Rs. 50 crore and product turnover above Rs. 25 crore for electricity generation.
Key audit implications: Cost Auditor appointment — Form CRA-2 filing with MCA within 180 days of start of financial year or within 30 days of Board approval, whichever is earlier; Cost records — maintenance in CRA-1 format; cost statements per CAS 1-24; Cost Audit Report — Form CRA-3, submitted by the cost auditor to the Board within 180 days of year end; filed by the company with MCA in Form CRA-4 within 30 days of receipt; Reconciliation Statement — CRA-3 reconciliation with financial statements; New cost centres required — FGD Plant; BESS Operations; Green Hydrogen Unit; Integrated Mine; CERC true-up support — cost audit report provides basis for regulatory cost verification. Refer Chapter 14.

5.8.3 SEBI LODR Regulations 2015

Coverage: Listing Obligations and Disclosure Requirements for listed companies like Audit Committee; related party transactions; corporate governance; continuous disclosures; BRSR.
Applicable to: Listed power sector companies like NTPC; NHPC; PGCIL; Adani Green; Tata Power; Torrent Power; etc.
Key audit implications: Audit Committee — constitution; independence; functions; quarterly reporting by internal audit; Related party transactions — prior approval; arm's length; material RPT shareholder approval; BRSR — mandatory for the top 1,000 listed companies from FY 2022-23; BRSR Core reasonable assurance phased in from FY 2023-24, starting with the top 150; Continuous disclosures — material events; price-sensitive information; trading window; Insider trading — UPSI management; trading window closure; pre-clearance; Annual Report — accuracy of all regulatory compliance statements. Refer Chapter 14.

5.8.4 Ind AS — Indian Accounting Standards

The following Ind AS have specific and significant implications for power sector entities:

Ind AS	Topic	Power Sector Application
Ind AS 114	Regulatory Deferral Accounts	Regulatory asset and liability accounting for rate-regulated entities; DISCOMs; TRANSCOs
Ind AS 115	Revenue from Contracts	PPA revenue recognition; capacity charges; variable charges; transmission charges
Ind AS 116	Leases	Rail wagon leases; land leases; transmission corridor RoW; right-of-use asset
Ind AS 36	Impairment	Stranded asset risk for older coal plants; recoverable amount; value-in-use
Ind AS 37	Provisions	Mine closure liability; ash pond restoration; FGD environmental obligation; decommissioning

Ind AS	Topic	Power Sector Application
Ind AS 109	Financial Instruments	Electricity derivatives; interest rate hedging; coal price hedging; ECL on DISCOM trade receivables
Ind AS 19	Employee Benefits	Actuarial valuation of PF; gratuity; leave; post-retirement medical; experience adjustments
Ind AS 21	Foreign Exchange	Imported coal payables; ECB; forward contract accounting
Ind AS 38	Intangible Assets	Software for SCADA/EMS; mining rights; amortisation period
Ind AS 105	Non-Current Assets Held for Sale	Retirement of old generating units; classification criteria

5.9 Direct Tax Laws

5.9.1 Income Tax Act 2025

Coverage: The Income Tax Act 2025 came into force on 1 April 2026, replacing the Income Tax Act 1961. The new Act reduces sections from 819 to 536 and introduces the concept of "Tax Year" replacing "Previous Year" and "Assessment Year."

Dual Reference Framework:

Period	Applicable Law	Key Implication
Up to 31 March 2026	Income Tax Act 1961	All assessments; appeals; TDS deductions; returns for this period governed by 1961 Act
From 1 April 2026 (Tax Year 2026-27 onwards)	Income Tax Act 2025	New section numbers; new TDS payment codes; new form numbers

TDS — New Framework under Income Tax Act 2025 (from 1 April 2026):

All TDS sections (194C; 194J; 194I; 194Q etc.) are now reported through Numeric Payment Codes: Refer Appendix A3.3 for details.

TDS Forms — Updated: Refer Appendix A3.4 for details.

Key audit implication: ERP systems (SAP/Oracle) must be reconfigured to use new payment codes from 1 April 2026. Using old section numbers in TDS returns for Tax Year 2026-27 transactions will cause portal validation errors. Internal auditors should verify ERP reconfiguration and test TDS filing for the first quarter of Tax Year 2026-27.

Section 37(2)(g) — MSME 45-Day Payment Disallowance:

- ✓ Payments to micro and small enterprises not made within the MSMED Act time limit (maximum 45 days) are disallowed in the year of accrual — Section 37(2)(g) of the 2025 Act, corresponding to Section 43B(h) of the 1961 Act (from AY 2024-25);
- ✓ Significant impact for power companies with MSME O&M vendors; spares suppliers; civil contractors
- ✓ Verify quarterly: outstanding MSME payables beyond 45 days; compute disallowance; provision

Section 147 — Power Generating Undertakings:

- ✓ available only to undertakings that began generation, transmission or distribution by 31 March 2017, and not to companies opting for the concessional tax regime

- ✓ Income-linked deduction — 100% of profits for any 10 consecutive years for eligible power undertakings;
- ✓ Form No. 35 under Rule 69 of the Income-tax Rules, 2026 — filing before due date of ITR is mandatory; late filing disqualifies the deduction

Concessional Tax Rate — Section 201 (Production Deadline Passed):

- ✓ 15% concessional rate for new manufacturing companies including new RE project entities
- ✓ Production commencement deadline was 31 March 2024 — this has now passed
- ✓ Audit risk: verify that entities claiming this rate had actually commenced production by 31 March 2024

Transfer Pricing:

- ✓ Applicable to related party coal imports through group trading arm; inter-company service charges; management fees
- ✓ Form No.48 under the Income-tax Rules, 2026— verify timely filing
- ✓ CbCR (Country-by-Country Reporting) for groups with overseas presence and revenue above Rs. 5,500 crore. Refer Section 8.2.6.

5.9.2 Income Tax Act 1961 — Legacy Applicability

The Income Tax Act 1961 remains applicable for all assessment years up to AY 2026-27 (i.e., transactions/income up to 31 March 2026); pending assessments; appeals at CIT(A); ITAT; High Court; Supreme Court; and carry-forward losses and MAT credits accumulated under the 1961 Act.

Internal auditors must maintain parallel tracking of: (a) legacy matters under Income-tax Act, 1961 and (b) current year compliance under Income Tax Act 2025. Refer Appendix 3 for details.

5.10 Goods and Services Tax

5.10.1 GST Acts — CGST; IGST; SGST 2017

Coverage: GST applies to supply of goods and services. Supply of electricity is exempt from GST. However, inputs used in generation — coal; equipment; services — attract GST at applicable rates. ITC is available on taxable supplies but must be reversed for exempt supplies.
Applicable to: All power sector entities.
GST Transaction Matrix — Power Sector: Refer Appendix A4.1 for details.
GST Compliance Checklist: E-invoicing (IRN and QR Code) — mandatory for turnover above Rs. 5 crore; verify for all B2B transactions; GSTR-1 vs. GSTR-3B reconciliation — monthly; identify mismatches; GSTR-2B reconciliation — ITC available vs. claimed; reconcile mismatches; GSTR-9 / GSTR-9C — Annual return and reconciliation statement; Table 8A reconciliation; e-Way Bill — coal movement; validity period; extension for transit delays; ITC apportionment — Rule 42/43 computation; proportionate reversal for exempt supply (electricity); RCM payments — GTA; legal services (including advocate fees); security services supplied by non-body-corporates; GST TDS provisions — applicable to certain government entities; compliance verification. Refer Chapter 14.

5.11 Customs Duty — Imported Coal and Equipment

5.11.1 Customs Act 1962

Coverage: Governs import and export of goods including coal. Customs duty rates; valuation; HSN code classification; exemptions; and enforcement.
Applicable to: Power sector entities importing coal; importing capital equipment.

Key audit implications for imported coal:

Area	Audit Check
HSN Code Classification	Thermal coal — HSN 2701; verify correct classification; duty differential for different grades
Basic Customs Duty (BCD)	Current rate on thermal coal; AIDC; SWS — verify computation
IGST on Import	18% on coal; ITC claim verification; Bill of Entry accuracy
Customs Valuation	CIF value for assessment; transaction value vs. customs value; valuation dispute
End-Use Exemption	Duty exemption for specified imports — end-use certificate compliance; post-import verification
Transfer Pricing	Related party coal imports — arm's length price; Form No. 48 (TP report under Rule 85 of the Income-tax Rules, 2026) compliance
Anti-Dumping Duty	Check for any anti-dumping duty on imports from specific countries
Bill of Entry	Document verification; date of filing; duty payment; assessment order

Refer Section 8.2.6.

5.12 Labour Laws

5.12.1 Four Labour Codes — Overview and Status

The four Labour Codes — the Code on Wages 2019, the Industrial Relations Code 2020, the Code on Social Security 2020 and the Occupational Safety, Health and Working Conditions Code 2020 — consolidate 29 central labour laws and were brought into force from 21 November 2025. State rules under the Codes are being notified progressively, and auditors should verify the rules in force in each state where the entity operates. Obligations for periods before that date continue to be tested under the earlier laws. Refer Appendices A5.1 and A5.2.

5.12.2 Earlier Labour Laws — Corresponding Code Provisions

Factories Act 1948 (OSH Code) — Factory licence; safety officer; welfare officer; welfare facilities. Refer Appendix 5.

Contract Labour (Regulation and Abolition) Act 1970 (OSH Code) — Principal employer registration; contractor licence; wage payment; ESI/PF coverage of contract labour. Refer Section 14.7 and Appendix 5.

Building and Other Construction Workers (BOCW) Act 1996 (**OSH Code and Code on Social Security)** — Cess on construction contracts (1% of cost); registration of workers; welfare fund. Refer Appendix 5.

OSH Code 2020 (subsuming the Mines Act 1952) — Labour conditions for mine workers — shift roster; rest days; overtime; competency — in addition to safety (covered under Section 5.6.1). Refer Chapter 9.

POSH (Prevention of Sexual Harassment) Act 2013 — Internal Complaints Committee (ICC) constitution; external member inclusion; annual report to District Officer; complaint tracking; awareness training. Applies to all workplaces; an ICC is mandatory where 10 or more are employed. Refer Appendix 5.

EPF and Miscellaneous Provisions Act 1952 and ESI Act 1948 (Code on Social Security) — Monthly ECR filing; TRRN; delayed payment interest; employer contribution accuracy; coverage of contract workers. Refer Section 14.7 and Appendix 5.

Inter-State Migrant Workmen Act 1979 (OSH Code) — Registration of migrant workers; displacement allowance; journey fare; applicable for construction sites with migrant labour. Refer Appendix 5.

5.13 Transport Laws

5.13.1 Railways Act 1989

Coverage: Governs railway transportation including freight tariff; rake supply; demurrage; and claims.

Applicable to: GENCOs receiving coal by rail; entities with railway sidings.

Key audit implications: Tripartite Agreement compliance — GENCO-CIL-Railways; rake supply vs. commitment; Railway Freight — correct tariff classification; freight invoice verification; Demurrage and Wharfage — wagon detention beyond free time; charges tracking; Shortage Claims — filing within 6 months of consignment delivery; documentation; recovery tracking; Railway siding maintenance — coordination with Railways for repairs; POH (Periodic Overhaul) wagon availability — planning impact. Refer Chapter 8.

5.13.2 Motor Vehicles Act 1988 (as amended by Motor Vehicles (Amendment) Act 2019)

Coverage: Governs road transportation including vehicle fitness; overloading; GPS tracking; e-challans; and third-party insurance. The 2019 Amendment significantly enhanced penalties and introduced e-challans. GPS tracking is required where state rules or the transport contract so provide.

Applicable to: GENCOs transporting coal by road; mine operators.

Key audit implications: Vehicle fitness certificate — validity; roadworthiness; GPS tracking — where required by state rules or the transport contract; verify installation and functioning; Overloading compliance — NGT directions on coal truck overloading; Tarpaulin cover — NGT mandate for coal trucks; dust pollution control; PUC (Pollution Under Control) certificate — validity for fleet vehicles. Refer Chapter 8.

5.13.3 Carriage of Goods by Sea Act 2025 and Related Shipping Laws

Coverage: Governs sea transport of goods including coal imports — bill of lading; cargo claims; laytime; demurrage.

Applicable to: Power sector entities importing coal by sea.

Key audit implications: Bill of Lading — document verification; quantity and quality as per B/L; Laytime and Demurrage — loading/unloading time allowed vs. actual; demurrage/despatch computation; Cargo claims — shortage claims against shipping company; time limits (one year from delivery); UCP 600 — Letter of Credit compliance for coal import payments; Draft survey / Displacement survey — accuracy of quantity measurement at port; third-party verification. Refer Chapter 8.

5.13.4 Major Port Authority Act 2021

Coverage: Governs major ports; tariffs for cargo handling, storage and other services are fixed by each Board of Major Port Authority, TAMP having been abolished under the Act.

Applicable to: Power sector entities importing coal through major ports.

Key audit implications: Port charges — verify against the Port Authority's notified Scale of Rates; stacking and quality preservation; coal GCV analysis at port; port storage charges. Refer Chapter 8.

5.13.5 Legal Metrology Act 2009

Coverage: Governs standards of weights and measures; calibration; verification of weighing instruments.
Applicable to: All power sector entities using weighbridges for coal measurement.
Key audit implications: Weighbridge calibration — Legal Metrology Act compliance; verification by certified agency; sealing records; frequency; Weighbridge software — manipulation risk; access control; audit trail; CCTV at weighbridge — recording; storage; access; independent verification; Railway rake weight vs. weighbridge weight — systematic variance analysis; Weighbridge accuracy — independent check weighments; spot verification. Refer Chapter 8.

5.14 IT and Cyber Laws

5.14.1 Information Technology Act 2000 (as amended 2008)

Coverage: Governs electronic records; digital signatures; cybercrime; and Critical Information Infrastructure (CII) protection.
Applicable to: All power sector entities.
Key audit implications: key systems are notified as protected systems (CII) under Section 70; NCIIPC oversight; bi-annual security audit; Electronic records — admissibility; retention; integrity; Cybercrime — Section 66 computer-related offences; incident reporting; Data protection — DPDP Act 2023 applies alongside for personal data.

5.14.2 CERT-In Directions 2022

Coverage: Mandatory cybersecurity directions issued by CERT-In under Section 70B of the IT Act. Effective from June 2022.
Applicable to: All power sector entities as Critical Information Infrastructure operators.
Key audit implications: 6-hour mandatory reporting of cybersecurity incidents to CERT-In; 180-day log retention — ICT system logs; network logs; application logs; NTP server synchronisation — mandatory use of NTP servers; synchronised with NIC or NPL NTP servers; Annual VAPT — CERT-In empanelled agency; finding remediation tracking. Refer Chapter 14 and Appendix 7.

5.14.3 Digital Personal Data Protection Act 2023 (DPDP Act)

Coverage: Governs collection; processing; storage; and transfer of personal digital data. Establishes obligations for Data Fiduciaries and rights for Data Principals.
Applicable to: DISCOMs handling consumer data through smart meters; billing systems. All power sector entities with employee data; HR systems.
Key audit implications: Data Fiduciary obligations — lawful basis for processing; purpose limitation; data minimisation; Consumer data in smart meters — consent; access controls; Data breach notification — Data Protection Board notification; CERT-In reporting within 6 hours; Data retention limits — not beyond the purpose of processing; DPDP Rules 2025 — notified; specify Data Fiduciary obligations including consent framework, Data Protection Officer appointment, grievance redressal mechanism, and breach notification to Data Protection Board. Compliance timelines phased; verify entity's current implementation status. Refer Chapter 14.

5.14.4 CEA Cyber Security Guidelines for Power Sector 2021

Coverage: Mandatory cybersecurity guidelines issued by CEA for all power utilities. Cover IT and OT security; incident response; vendor management; and supply chain security.
Applicable to: All power sector entities.
Key audit implications: OT/SCADA security — IT-OT network segmentation; firewall; IEC 62443 compliance; Incident Response Plan — documented; tested; CERT-In notification procedures; Vendor management — security assessment of critical vendors; access controls; Supply chain security — verification of equipment origin; no unauthorised equipment; Annual cybersecurity audit — by empanelled agency; findings remediation. Refer Chapter 14 and Appendix 7.

5.15 Other Applicable Laws

5.15.1 Foreign Exchange Management Act 1999 (FEMA)

Coverage: Governs foreign exchange transactions — import payments; export receipts; external commercial borrowings (ECB); foreign investments; and hedging.
Applicable to: Power sector entities importing coal; entities with ECB; entities with foreign investment.
Key audit implications: Authorised Dealer Bank — all forex transactions through AD bank; compliance; ECB compliance — end-use; reporting to RBI; all-in cost ceiling; Coal import payments — FEMA compliance; authorised dealer; documents; Hedging — RBI-approved hedging instruments; FEMA compliance; accounting treatment under Ind AS 109; Forward contracts — mark-to-market; hedge accounting; FEMA hedging guidelines.

5.15.2 Right to Information Act 2005

Coverage: Gives citizens the right to information from public authorities. Power sector PSUs are public authorities under the RTI Act.
Applicable to: All government-owned power sector entities — Central and State PSUs.
Key audit implications: PIO (Public Information Officer) — designated; adequately staffed; RTI response timeliness — 30-day statutory limit; verify compliance; First Appeal disposal — 30-45 day limit; Proactive disclosure — Section 4 disclosures on company website; completeness; updation frequency; Information Commission orders — compliance within stipulated period.

5.15.3 Right to Fair Compensation and Transparency in Land Acquisition, Rehabilitation and Resettlement Act 2013 (RFCTLARR Act)

Coverage: Governs acquisition of land for public purposes including power projects and mines. Provides for Social Impact Assessment; consent of affected families; fair market value compensation; and R&R entitlements.
Applicable to: GENCOs and TRANSCOs acquiring land for new projects; mine operators acquiring land for mining.
Key audit implications: SIA compliance — Social Impact Assessment conducted; SIA Authority approval; Consent — 80% of affected families (private company) or 70% (PPP project); Compensation — market value (with a multiplier of up to 2 in rural areas) plus value of assets, plus 100% solatium; verify adequacy; R&R entitlements — house; land; employment; annuity; subsistence allowance — actual delivery vs. entitlement; Grievance Redressal — RFCTLARR mandated mechanism; complaints tracking; Land acquisition cost in tariff — CERC allows actual acquisition cost; verify accuracy. Refer Chapter 14.

5.15.4 Prevention of Corruption Act 1988

Coverage: Governs corruption offences by public servants. Applicable to government employees in power sector PSUs.
Applicable to: All government-owned power sector entities.
Key audit implications: Propriety audit — expenditure that may indicate corrupt practices; Vigilance interface — internal audit findings that may constitute corruption offences — refer vigilance; do not investigate independently; Gifts and hospitality — compliance with CVC guidelines on gift limits for public servants; Integrity Pacts in contracts — compliance with anti-corruption clauses; Disproportionate assets — where audit findings suggest unexplained wealth of employees; refer to vigilance immediately. Refer Section 1.8.

5.15.5 Public Premises (Eviction of Unauthorised Occupants) Act 1971

Coverage: Enables government entities to evict unauthorised occupants from government premises including PSU townships and residential quarters.
Applicable to: Power sector PSUs with townships; colonies; residential quarters.
Key audit implications: Unauthorised occupation — retired or resigned employees continuing to occupy quarters; Quarter allotment records — eligibility vs. actual allotment; correct category; Recovery of rent arrears — outstanding dues from current and former occupants; Eviction proceedings — pending cases; timeline. Refer Chapter 14.

5.15.6 Boilers Act, 2025 and Indian Boiler Regulations, 1950 (as amended)

Coverage: Governs construction; inspection; registration; and certification of boilers and pressure vessels in thermal power plants.
Applicable to: All thermal generating companies.
Key audit implications: Boiler registration — valid IBR certificate for each boiler; periodic inspection by statutory boiler inspector; Safety valve testing — annual testing records; pressure settings; Boiler inspection — pre-commissioning; periodic; post-repair inspections; certificates; IBR-approved materials — for pressure parts; welding qualifications; inspection of welds; Capital works — IBR clearance before commissioning of new/repaired pressure parts. Refer Chapter 8.

5.16 Regulatory Filing Calendar

Power sector entities have extensive mandatory regulatory filing obligations. A summary of key filings by category is in Appendix A6.1.

6. POWER SECTOR ENTITIES — OVERVIEW FOR INTERNAL AUDITORS

6.0 Introduction

Before commencing an internal audit of any power sector entity, the internal auditor must have a clear understanding of what type of entity is being audited — its business model, regulatory framework, revenue sources, cost structure, key risks, and the governance framework applicable to it. This chapter provides that foundational understanding for each major category of power sector entity.

This chapter is designed as a practical orientation guide as it gives the internal auditor enough entity-specific context to read the audit programme for that entity intelligently and ask the right questions. Detailed audit procedures for each entity type are provided in Chapters 8 through 13.

A critical preliminary step before reading any entity description is to determine the exact type of entity being audited. The power sector has several hybrid and non-standard entity configurations that do not fit neatly into a single category. Chapter 7 is dedicated to these special configurations and provides a decision framework to guide the internal auditor to the correct audit approach.

6.1 Generation Companies (GENCOs)

6.1.1 What a GENCO Does

A generation company owns, operates, and maintains electric generating stations. It sells electricity either under long-term power purchase agreements (PPAs) with distribution companies or state utilities, or in the short-term market through power exchanges or bilateral arrangements. Revenue consists primarily of capacity charges — fixed charges for making the plant available and energy charges — variable charges for actual generation.

6.1.2 Types of GENCOs

Thermal GENCOs — Operate coal-based, gas-based, or oil-based power plants. Coal-based thermal plants are the most common and most significant from an audit perspective — fuel management audit alone is a major audit area. Examples: NTPC Limited; TGGENCO; MPPGCL; MAHAGENCO; Adani Power; Tata Power.

Hydro GENCOs — Operate hydroelectric power stations — run-of-river, storage-based, or pumped storage. Revenue is seasonal and dam safety compliance is a critical audit area. Examples: NHPC Limited; THDC India Limited; SJVN Limited; APGENCO (hydro).

Renewable Energy GENCOs — Operate solar; wind; biomass; or hybrid RE projects. Revenue depends on generation performance (CUF; PR); REC registration; and RPO compliance. Examples: SECI-auctioned RE project developers; Adani Green Energy; ReNew Power; Greenko.

Nuclear GENCOs — Operate nuclear power stations under AERB oversight. Specialised regulatory framework applicable mainly to NPCIL. Brief audit reference is provided in Section 10.9.

Integrated GENCOs — Thermal GENCOs that also operate captive coal mines to supply fuel to their own power plants. The integration creates additional audit areas like mine operations; coal-to-plant transfer pricing; CERC mine input price determination. Examples: NTPC Limited (Pakri Barwadih; Dulanga; Chatti-Bariatu mines); TGGENCO (Tadicherla-I mine); MPPGCL etc.

6.1.3 Revenue Model

Under Section 62 — Cost Plus Regulated Tariff: Annual Fixed Charges (AFC) are recovered in full when the declared availability reaches the normative level (NAPAF) and pro-rata below it, irrespective of actual generation; Energy Charges are received for scheduled generation, with fuel cost passed through at normative SHR; Fuel Price Adjustment (FPA) adjusts monthly for actual versus normative fuel cost and is passed through to beneficiary DISCOMs; an Incentive is payable for performance above the normative level.

Under Section 63 — Competitive Bid Tariff: Fixed and variable charges as per bid price; no true-up or prudency check; Cost overruns borne by developer; fuel cost risk is developer's; Refer Section 7.7 for detailed audit implications.

Merchant Plants: Market-determined prices; no regulatory tariff; no capacity charge guarantee; Revenue = market price × units sold on exchange or bilaterally. Refer Section 7.6 for detailed audit implications.

6.1.4 Key Risks for Internal Audit

Fuel cost and GCV — Largest single risk; fuel is 60-70% of total cost; GCV manipulation can cost crores; ACQ shortfall penalties often not raised; Plant performance — SHR; APC; PAF — deviation from CERC norms affects tariff recovery; PAF manipulation through outage misclassification; Environmental compliance — FGD non-compliance; CEMS data integrity; ash utilisation; environmental compliance bond; Tariff petition data accuracy — Imprudent costs disallowed by CERC permanently; data misrepresentation in petition; Capital works — Large capital expenditure; fraud-prone; measurement book certification; CERC prudency risk on cost overruns; Procurement — High-value; long-term contracts; split orders to avoid approval; kickback risk; Mine operations (where applicable) — Production reporting; weighbridge fraud; MDO payment inflation.

6.1.5 Applicable Regulatory Framework

CERC Tariff Regulations 2024-29 (central GENCOs under CERC jurisdiction); SERC tariff orders (state GENCOs under SERC jurisdiction); CEA Technical Standards for construction; metering; connectivity; MoEFCC Environmental Standards (S.O. 3305(E) 2015 and amendments); OSH Code 2020 (subsuming the Mines Act, 1952), Coal Mines Regulations 2017 and DGMS regulations (for captive mine GENCOs); SHAKTI Policy 2017 and FSA with CIL/SCCL (for coal-based plants); Dam Safety Act 2021 (for hydro GENCOs); CERC RE Tariff Regulations 2024-27 (for RE GENCOs). For detailed audit procedures — refer Chapter 8 (Thermal GENCO); Chapter 9 (Integrated Mine); Chapter 10 (Renewable Energy; Hydro; BESS).

6.2 Transmission Companies (TRANSCOs)

6.2.1 What a TRANSCO Does

A transmission company owns and operates transmission lines and substations for conveyance of electricity from generating stations to load centres. It does not buy or sell electricity as it provides the infrastructure over which electricity flows and earns transmission charges approved by CERC/SERC for providing this infrastructure service.

6.2.2 Types of TRANSCOs

Central Transmission Utility (CTU) — Central Transmission Utility of India Limited (CTUIL), a wholly owned subsidiary of PGCIL, has been the notified CTU since 1 April 2021 and plans the

ISTS and bills ISTS charges. PGCIL owns the largest share of the ISTS, which is operated by Grid-India. ISTS charges are shared among users under the CERC Sharing Regulations 2020.

State Transmission Utilities (STUs) — Each state has a State Transmission Utility typically a separate company or a ring-fenced division of the state utility. STUs own and operate the intra-state transmission system. Revenue from intra-state transmission charges approved by SERC.

TBCB SPVs (Tariff Based Competitive Bidding Special Purpose Vehicles) — Private entities that have won competitive bids for specific transmission projects under the TBCB framework. These SPVs own and operate specific transmission lines; earn transmission charges at the competitively bid tariff. Subject to specific CERC compliance requirements including SCADA connectivity and metering standards.

6.2.3 Revenue Model

Annual Transmission Charges (ATC) — approved by CERC/SERC for the year; for ISTS, shared among users under the CERC Sharing Regulations 2020 and billed monthly by CTUIL; Availability-based — charges linked to transmission system availability; normative availability 98% under CERC 2024-29 norms; No fuel cost; no energy cost — pure infrastructure earnings model; Incentive for availability above normative level.

6.2.4 Key Risks for Internal Audit

Transmission tariff billing accuracy — ATC billing to beneficiaries; monthly reconciliation with NLDC (Implementing Agency) and SLDC computations; Capital works — New transmission lines; substations; large capex; fraud-prone; capitalization timing affects tariff recovery; Capitalisation timing — COD of new transmission assets; premature or delayed capitalization materially affects tariff entitlement; O&M contracts — Line maintenance; substation maintenance; high-value; long-term contracts; fraud-prone; OT/SCADA security — Energy Management System (EMS); SCADA for substation remote control; critical infrastructure; CEA Cyber Security Guidelines 2021 compliance; ISTS charges reconciliation — charges computed by NLDC and billed by CTUIL; monthly verification against bills received by users; GNA compliance — Connectivity and General Network Access Regulations 2022; registration; queue position; connectivity charges.

6.2.5 Applicable Regulatory Framework

CERC Tariff Regulations 2024-29 — for PGCIL and other Section 62 transmission licensees; tariff adopted under Section 63 for TBCB projects; SERC tariff orders — for STUs; CERC Connectivity and GNA Regulations 2022; CERC (Sharing of ISTS Charges and Losses) Regulations 2020; CEA Grid Standards Regulations 2010; IEGC 2023; CEA Technical Standards for construction; connectivity; safety. For detailed audit procedures — refer Chapter 11.

6.3 National, Regional and State Load Despatch Centres

6.3.1 What Load Despatch Centres Do

Load Despatch Centres (LDCs) are the nerve centres of the power system. They do not own generating assets or transmission lines — they are the system operators responsible for:

- ✓ Scheduling and despatching generating stations in real time
- ✓ Managing grid frequency and voltage security
- ✓ Coordinating planned and forced outages of generating and transmission equipment
- ✓ Providing metered data for energy and deviation (DSM) accounts, which are issued by the Regional Power Committees, and operating the regional deviation pool accounts

- ✓ Operating certain market functions — NLDC operates the REC registry; facilitates SCED; schedules and settles cross-border electricity trade

6.3.2 Hierarchy of Load Despatch Centres

National Load Despatch Centre (NLDC) — Operated by Grid-India (Grid Controller of India Limited, a Government of India enterprise under the Ministry of Power). Responsible for optimal scheduling and despatch of generating stations connected to the national grid; Security Constrained Economic Despatch (SCED); international electricity trading with Nepal; Bhutan; Bangladesh; and operation of the REC registry.

Regional Load Despatch Centres (RLDCs) — Five RLDCs — Northern; Southern; Eastern; Western; and North-Eastern — operate under Grid-India. Each RLDC is responsible for optimal scheduling and despatch within its region; regional ABT; and coordination of inter-regional power flows.

State Load Despatch Centres (SLDCs) — Operated by each state — either as a function of the STU or as a separate entity. Responsible for intra-state scheduling; state ABT; coordination with RLDC; outage coordination within the state; and operation of the state grid.

6.3.3 Revenue Model

System operation charges — charged to generators and buyers connected to ISTS (for NLDC/RLDC) or state grid (for SLDC); approved by CERC/SERC; REC registry fees — fees charged by NLDC for REC issuance and registry services.

6.3.4 Key Risks for Internal Audit

Scheduling accuracy — Day-ahead and real-time scheduling; DSM charge computation and settlement accuracy; System operation charges — Approval by CERC/SERC; billing to users; timely recovery; SCADA/EMS cybersecurity — Critical infrastructure and primary target of cyber attacks; CEA Cyber Security Guidelines 2021 compliance; REC registry operations (NLDC) — Issuance accuracy; trading compliance; registry integrity and cybersecurity; Grid incident documentation — Frequency deviation events; blackout records; post-event analysis; CERC reporting; Cross-border energy accounting — International trading with Nepal; Bhutan; Bangladesh; settlement accuracy; Ancillary services — Procurement; payment to providers; recovery of ancillary service charges from users.

6.3.5 Applicable Regulatory Framework

CEA Grid Standards Regulations 2010; Indian Electricity Grid Code (IEGC) 2023; CERC (Deviation Settlement Mechanism) Regulations 2024; CERC (Ancillary Services) Regulations 2022; CERC (Fees and Charges of Regional Load Despatch Centre and other related matters) Regulations — system operation charges; CEA Cyber Security Guidelines 2021, particularly relevant for SCADA/EMS systems in LDCs. For detailed audit procedures — refer Chapter 11.

6.4 Distribution Companies (DISCOMs)

6.4.1 What a DISCOM Does

A distribution company is the last mile of the power sector as it receives electricity at high voltage from the transmission system and distributes it to end consumers at lower voltages. The DISCOM is the billing and collection entity as it is the commercial face of the power sector that the consumer

sees. It is also the entity most exposed to financial risk from AT&C losses; regulatory asset accumulation; inadequate tariff revision; and dependence on state government subsidies.

6.4.2 Types of DISCOMs

State Government-Owned DISCOMs — The majority of electricity distribution in India is handled by state government-owned utilities. Most states have one or more state DISCOMs covering different geographical areas. Examples: TGSPDCL; TGNPDCL (Telangana); MSEDCL (Maharashtra); UPPCL (Uttar Pradesh); KESCO (Kanpur); BESCOM (Karnataka) etc.

Private Distribution Licensees — Private or majority-private licensees operating under SERC licence. Examples: BSES Rajdhani; BSES Yamuna; Tata Power Delhi Distribution; Tata Power's four Odisha DISCOMs; Torrent Power (Ahmedabad, Surat); Adani Electricity Mumbai; CESC (Kolkata).

Franchisees — A DISCOM may appoint a distribution franchisee under a franchise agreement to collect revenue and maintain the network in a defined area, while remaining the licensee. Examples: Torrent Power in Bhiwandi (Maharashtra) and Agra (Uttar Pradesh).

6.4.3 Revenue Model

Retail tariff — collected from consumers based on SERC-approved tariff schedule; category-wise rates (domestic; commercial; industrial; agricultural); Cross-subsidy — industrial and commercial consumers subsidise agricultural and domestic consumers through higher tariffs; Fuel and Power Purchase Cost Adjustment (FPPCA) — automatic monthly pass-through under the Electricity (Amendment) Rules 2022, subject to SERC true-up; SERC approval required; Electricity Duty — collected on behalf of state government; not a DISCOM revenue; Open Access charges — cross-subsidy surcharge; wheeling charges from consumers using DISCOM network for open access; Direct Benefit Transfer (DBT) — State government subsidy — paid in advance under Section 65 for subsidised consumer categories; DBT to consumers where a state has adopted it; Non-tariff income — late payment surcharge; meter rental; new connection charges; theft detection fines.

6.4.4 Key Risks for Internal Audit

AT&C losses — Revenue leakage from technical losses; theft; billing errors; collection shortfall — highest risk area; largest single financial risk; Power purchase cost — Largest expense; prudency of purchase decisions; RPO/HPO compliance; emergency purchase justification; Regulatory asset accumulation — Deferred cost recovery; recoverability risk; inadequate SERC provisions; RDSS implementation — Smart meter rollout; grant utilisation; milestone achievement; procurement process; Consumer services — CGRF constitution and functioning; Electricity Ombudsman order compliance within 30 days; billing accuracy; connection timelines; DBT and subsidy — Beneficiary database accuracy; Aadhaar seeding; state government reimbursement lag; DBT reconciliation; Financial health — ACS-ARR gap; PFC and REC Limited loan covenants; working capital stress; payment to GENCOs beyond 45 days.

6.4.5 Applicable Regulatory Framework

SERC tariff orders — retail tariff; RPO; MYT compliance; Electricity (Rights of Consumers) Rules 2020 (as amended up to 2024) — consumer protection; standards of performance; Electricity (Amendment) Rules 2023 — captive plant definition; Rule 19 RE tariff framework; Electricity (Late Payment Surcharge and Related Matters) Rules 2022 — payment timelines to GENCOs; Electricity (Amendment) Rules 2022 — FPPCA; RDSS Operational Guidelines 2021 — grant conditions;

milestones; smart meter specifications; State Grid Code — intra-state scheduling; SLDC interface; CERC Power Market Regulations 2021 — for exchange-based power purchase; Smart Meter National Programme guidelines — metering standards; HES cybersecurity. For detailed audit procedures — refer Chapter 12.

6.5 Power Traders and Energy Exchanges

6.5.1 Power Traders

What they do: CERC-licensed power traders facilitate short-term and medium-term electricity transactions between generators and buyers on a bilateral basis. They earn a trading margin prescribed by CERC on the volume of electricity traded. Power traders must hold a valid CERC trading licence.

Classification: Category I traders handle unlimited volumes; Category II traders handle below a specified threshold. Category determines net worth requirement and trading limits.

Key risks for internal audit: CERC trading licence — validity; conditions compliance; annual reporting to CERC; Trading margin — does not exceed CERC-prescribed ceiling; correctly billed to counterparties; Volume of transactions — timely reporting to CERC; compliance with permitted volumes; Payment security from buyers — credit risk management; LC or advance payment; PPA compliance — accurate pass-through of terms between generator and buyer in bilateral trade; Counter-party KYC — due diligence on generators and buyers before executing trades.

6.5.2 Energy Exchanges — IEX, PXIL and HPX

What they do: Power exchanges provide an anonymous, double-sided auction platform for trading electricity and market instruments. The three licensed exchanges are IEX (Indian Energy Exchange), PXIL (Power Exchange India Limited) and HPX (Hindustan Power Exchange), and they operate under the CERC (Power Market) Regulations 2021 (Section 5.2.6). Their segments are the Day Ahead Market, Term Ahead Market, Real Time Market, Green Day Ahead Market and High Price Day Ahead Market. They also run sessions for Renewable Energy Certificates and Energy Savings Certificates. Electricity derivatives are covered in Section 13.6. The segments are defined in Section 3.7, and audit procedures are in 13.3–13.8.

6.5.3 Key Risks for Internal Audit — Exchange Participants

Member registration and compliance — portfolio management; position limits; reporting; Settlement accuracy — exchange settlement advices vs. books; bank account reconciliation; Board-approved trading policy — compliance; price prudency; authorized market segments; Collateral management — margins deposited; adequacy; return of excess collateral; Market coupling compliance — when implemented; unified clearing between IEX, PXIL and HPX. *For detailed audit procedures — refer Chapter 13.*

6.6 Subsidiary, SPV and Joint Venture Structures

6.6.1 Subsidiaries

Large power sector entities — particularly CPSUs like NTPC and NHPC have multiple subsidiaries for specific purposes:

- ✓ **Project-specific subsidiaries** — Set up for a specific power project; typically merged into parent post-commissioning or operated separately

- ✓ **Functional subsidiaries** — NTPC Electric Supply Company (NESCL) for distribution; NTPC Vidyut Vyapar Nigam (NVVN) for trading; NLC India's subsidiaries
- ✓ **Mine development subsidiaries** — Set up for captive coal mine development before transfer to parent
- ✓ **RE subsidiaries** — Set up for solar/wind projects as separate legal entities for project finance. NTPC Green Energy Ltd (NGEL) is a direct subsidiary of NTPC established as the dedicated renewable energy holding vehicle; NTPC Renewable Energy Limited (NTPC REL) is in turn a direct subsidiary of NGEL, illustrating the two-tier subsidiary structure increasingly adopted by CPSUs to ring-fence renewable project finance from the parent's balance sheet and to facilitate independent equity raising at the intermediate holding level.

Internal audit implications for holding company: Monitoring subsidiary internal audit functions — adequacy of resources; independence; reporting; Group-level risk consolidation — risks at subsidiaries affecting holding company financial statements and reputational standing; Inter-company transactions — transfer pricing; management fees; loans; guarantees — arm's length compliance; Section 188 Companies Act; SEBI RPT regulations; Subsidiary performance monitoring — quarterly KPI review; CERC compliance status; financial health; Related party transaction approval — Board/Audit Committee pre-approval as required under Companies Act and SEBI LODR.

6.6.2 Special Purpose Vehicles (SPVs)

TBCB Transmission SPVs — Private entities that have won transmission projects through competitive bidding. Specific CERC compliance obligations; project-financed; lender oversight through Independent Engineer.

Generation Project SPVs — Set up by power developers for specific generation projects; project-financed; ring-fenced cash flows; escrow arrangements for debt service.

Internal audit implications for sponsoring entity: SPV governance — Board composition; independent directors; Audit Committee constitution; CERC/SERC compliance specific to SPV — tariff; connectivity; grid code; Lender covenants — DSRA; DSCR; Conditions Subsequent; Asset transfer — at end of concession period or project life; valuation; tax implications; Related party transactions between sponsor and SPV — management fees; O&M contracts; equipment supply.

6.6.3 Joint Ventures

Common JV structures in the power sector:

- ✓ **NTPC-BHEL Power Projects Private Limited (NBPPL)** — JV for EPC of power plants; construction management
- ✓ **State hydro JVs** — *central GENCO or Government of India JVs with state governments for hydro development; examples: THDC India Limited (NTPC and Government of Uttar Pradesh); SJVN Limited (Government of India and Government of Himachal Pradesh)*
- ✓ **RE JVs** — PSU JVs for large solar/wind projects with state governments or private parties

Internal audit implications for holding/lead company: JV agreement compliance — equity contributions on schedule; profit sharing as per agreement; governance rights; Inter-partner transactions — management fees; technical services; equipment supply — arm's length pricing; Related party considerations — JV transactions with partners; Section 188 Companies Act compliance; Exit provisions — pre-emption rights; drag-along; tag-along; valuation mechanism if

partner exits; Consolidation — JV financial results in consolidated accounts; Ind AS 111 and Ind AS 28 treatment.

6.7 Coal Supply Chain Entities — As Counterparties in Audit

Note: Coal supply chain entities like CIL; SCCL; railways; ports are not themselves subjects of internal audit under this Guidance Note. They are not primary entities as defined in Section 1.2.1. However, they appear as counterparties in the fuel management audit of thermal GENCOs. This section provides brief context on their role to help the internal auditor understand the counterparty they are dealing with during GENCO audit.

6.7.1 Coal India Limited (CIL) and Subsidiaries

CIL is the world's largest coal mining company. It supplies coal to thermal power stations through Fuel Supply Agreements. Its subsidiaries — CCL (Central Coalfields); SECL (South Eastern Coalfields); ECL (Eastern Coalfields); BCCL (Bharat Coking Coal); MCL (Mahanadi Coalfields); WCL (Western Coalfields); NCL (Northern Coalfields), each supply coal from their respective coalfields. For the internal auditor of a thermal GENCO: FSA is with the CIL subsidiary — not directly with CIL holding company; GCV disputes are settled through third-party sampling by CIMFR or another agency appointed under the FSA; ACQ shortfall penalty bills are raised on the specific CIL subsidiary; SHAKTI LoA is issued by CIL holding but executed with the subsidiary; e-auction coal is procured through CIL's e-auctions conducted on the MSTC and mjunction platforms.

6.7.2 Singareni Collieries Company Limited (SCCL)

SCCL is a joint venture between the Government of Telangana and the Government of India. It supplies coal primarily to power stations in Southern India — including TGGENCO; APGENCO; and NTPC stations in southern region. SCCL FSAs are separate from CIL FSAs but follow similar compliance frameworks for GCV measurement; ACQ; and shortfall penalties.

6.7.3 Railways

Indian Railways transports the bulk of domestic coal from mine to power plant. Key elements for internal audit of a GENCO: Tripartite Agreement — between GENCO; coal company; and Indian Railways on rake supply commitments; Rake allocation — monthly supply vs. commitment; shortfall follow-up; Railway freight tariff — periodic revision by Railway Board; correct classification and distance used in billing; Demurrage and wharfage charges — wagon detention beyond free time; charges computation and control; Railway siding at power plant — maintenance; coordination with Railways for upgradation.

6.7.4 Ports (for Imported Coal)

For power stations importing coal, major ports such as Paradip, Visakhapatnam, Kamarajar (Ennore) and Deendayal (Kandla), and non-major ports such as Mundra handle receipt, stacking, and loading onto rail/road for onward transport. Key elements for internal audit: Port handling charges — compliance with the port's notified Scale of Rates; competitive rate verification; Draft survey / displacement survey — independent surveyor for quantity measurement at port; Coal stacking — quality preservation; contamination risks; blending if required; Port storage charges — minimise dwell time; stacking charges audit.

7. SPECIAL ENTITY CONFIGURATIONS AND HYBRID AUDIT FRAMEWORK

7.0 Introduction

The power sector in India has several entity configurations that do not fit neatly into a single category. A thermal GENCO may also operate a captive coal mine allotted to it for fuel security. A coal company may have set up a power plant to sell electricity to the grid. An industrial company may have a captive power plant that partly sells surplus power on exchanges. A generating station may sell entirely at market prices without a regulated PPA. A single project may combine solar, wind, and battery storage under one tariff.

In each of these cases, applying a standard single-entity audit framework without first understanding the configuration leads to incomplete or misdirected audit. The internal auditor may apply the wrong benchmarks, miss entire regulatory compliance dimensions, or focus on areas of low risk while ignoring areas of high risk that are unique to the hybrid configuration.

This chapter provides a decision framework to help the internal auditor determine the correct audit approach when faced with a non-standard entity configuration. It establishes the **Lead Entity Rule** which determines which audit framework leads and which frameworks are addenda and then provides specific guidance for each of the eight most common special configurations encountered in the power sector.

This chapter is designed to be used before opening any other chapter of this Guidance Note as it is the entry point for any auditor who is not certain which audit framework applies to the entity being audited.

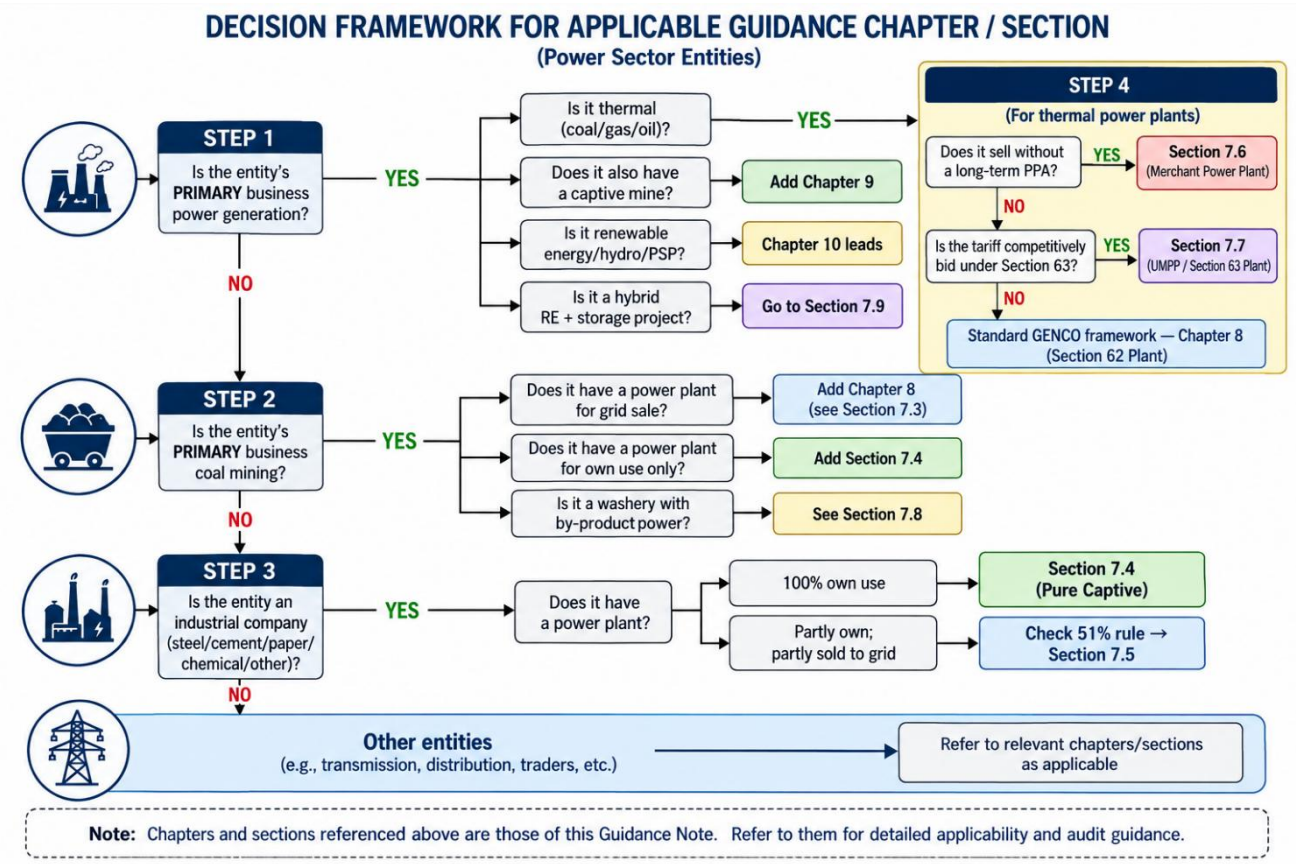
7.1 The Lead Entity Rule — Decision Framework

Before opening any chapter of this Guidance Note and before designing an audit programme, the internal auditor should answer one fundamental question:

"What is the primary business of this entity and what regulatory framework governs that primary business?"

The answer determines the **Lead Entity Framework**. All other business activities of the entity are then treated as addenda to the lead framework as each addendum adds specific audit procedures without displacing the lead framework.

7.1.1 The Decision Flowchart



7.1.2 The Most Important Principle

The same physical asset like a coal-fired power plant can be a regulated GENCO subject to CERC Section 62 tariff; a competitive bidder with a fixed tariff under Section 63; a merchant plant selling at market prices; or a captive plant whose output never enters the regulated grid. The audit procedures, applicable norms, benchmarks, and risk areas are fundamentally different in each case.

The Lead Entity Rule prevents the most common error in power sector audit: applying the Section 62 GENCO framework to a merchant plant, or applying the industrial company cost centre approach to an entity that actually sells significant quantities of electricity and should be treated as a GENCO for regulatory purposes.

Where an entity spans two or more categories and many power sector entities do, the lead framework covers the primary business fully, and addendum frameworks add only the procedures that are genuinely unique to the secondary activity. There is no duplication.

7.2 GENCO with Captive Coal Mine — Integrated GENCO

7.2.1 Configuration Description

A thermal GENCO that owns and operates one or more captive coal mines allotted to it under the Coal Mines (Special Provisions) Act 2015 for the purpose of supplying coal to its own generating stations. The GENCO is the primary entity; the mine is integral to the GENCO's fuel security strategy and is not a separate business unit.

This is the most common hybrid configuration in India's thermal power sector. Allotment of captive coal blocks to power sector PSUs accelerated after the Supreme Court's 2014 order cancelling earlier allocations and the Coal Mines (Special Provisions) Act 2015.

Examples: NTPC Limited (Pakri Barwadih mine in Jharkhand; Dulanga mine in Odisha; Chatti-Bariatu mine in Jharkhand); TGGENCO (Tadicherla-I mine in Telangana); NLC India Limited etc.

7.2.2 Regulatory Interface

This configuration involves two distinct and parallel regulatory frameworks:

As GENCO: Regulated by CERC or the applicable SERC under the Electricity Act 2003. Tariff determined under CERC Tariff Regulations 2024-29 or SERC equivalent. Subject to CEA technical standards; MoEFCC environmental standards for the power plant; and all other power sector compliance obligations.

As Mine Operator: Regulated by DGMS under the Mines Act 1952 (OSH Code from 21 November 2025) and the Coal Mines Regulations 2017; by the Ministry of Coal under the Coal Mines (Special Provisions) Act 2015 and MMDR Act 1957; by the State Government for the mining lease and royalty; and by MoEFCC for the mine's environmental clearance.

The Critical Interface — CERC (or the SERC for a state GENCO) Mine Input Price Petition: This is the most important and most unique regulatory feature of integrated GENCOs. When a GENCO operates a captive mine and supplies coal from that mine to its own power plant, the price at which coal is transferred from the mine to the plant is **not** left to management discretion. CERC determines this input price through a separate mine input price petition filed by the GENCO. The CERC-determined input price is then used for FPA computation, coal cost claims in the tariff petition, and CERC true-up.

This means the internal auditor must verify two aspects simultaneously: that the mine is producing coal at reasonable cost (mine audit) AND that the coal is being transferred to the power plant at the CERC-determined price, not at an inflated or deflated value that would distort either the mine's cost accounts or the power plant's tariff claims.

7.2.3 Audit Framework

Lead Framework: GENCO audit — Chapter 8. The primary business is power generation; the mine is an input supply chain function. Chapter 8 audit procedures apply in full.

Addendum Framework: Mine audit — Chapter 9. All mine-specific audit procedures in Chapter 9 apply additionally. These do not replace any Chapter 8 procedures.

Specific Interface Audit Points unique to this configuration:

(a) Coal Transfer Pricing: Verify that coal is being transferred from the mine to the power plant at the price as determined by CERC (or the SERC for a state GENCO) in the mine input price petition, not at actual cost if actual cost differs from the CERC-determined price, and not at any other management-determined price. The CERC petition should be filed and the order obtained; the transfer price in the books should match the order. Any deviation has tariff implications.

(b) Mine Cost Capitalisation vs Revenue: Mine development costs like shaft sinking; overburden removal for initial mine development; infrastructure construction may be capitalisable as part of the mine's capital cost. However, ongoing overburden removal during production is revenue

expenditure. The boundary is frequently a source of manipulation. Verify that the CERC's guidance on mine cost treatment is followed consistently.

(c) Mine-to-Plant GCV Verification: Reconcile, every month, the GCV sampled at mine dispatch with the GCV received at the plant. A systematic downward difference requires investigation (procedures in Sections 9.5.3 and 8.2.2).

(d) Dual Environmental Clearance Tracking: The mine has its own Environmental Clearance (EC) with its own set of conditions. The power plant has a separate EC. Both must be tracked independently. A failure on the mine EC does not affect the power plant EC and vice versa but both are the GENCO's responsibility and must appear in the internal audit compliance checklist.

(e) DMF and NMET Monthly Payments: Royalty, DMF, NMET, Reserve Price, Revenue Share (for auctioned blocks) and state levies such as Mineral Bearing Land Cess are the GENCO's obligations as mine operator. Verify them through the consolidated statutory payments register (Section 9.3).

(f) Separate Cost Centre Maintenance: Mine operations must be accounted for as a separate cost centre under the Companies (Cost Records and Audit) Rules 2014, and the cost auditor's report must cover the mine separately (see Section 7.3.3(a)).

7.3 Coal Company with Power Plant (Non-Captive — MoC-Led Entity)

7.3.1 Configuration Description

A coal company such as a subsidiary of Coal India Limited, or Singareni Collieries Company Limited, or a private coal washery operator that has set up a power plant to sell electricity to the grid or to specific buyers. Here the coal company is the primary entity; the power plant is ancillary to the core mining and coal production business.

This configuration is the mirror image of Section 7.2. In Section 7.2, a GENCO operates a mine as an addendum. In Section 7.3, a coal company operates a power plant as an addendum. The lead framework therefore reverses.

Examples: Singareni Thermal Power Plant (STPP); pit-head power plants operated by CIL subsidiaries; coal washery power plants using rejects or middlings; mine gas-based power plants at coal mines.

7.3.2 Regulatory Interface

As Coal Company (Primary): Regulated by Ministry of Coal; DGMS; OSH Code 2020 (subsuming the Mines Act, 1952); Coal Mines Regulations 2017. Coal production; dispatch; royalty; DMF; NMET; mine safety — all governed by the coal mining regulatory framework.

As Power Generator (Ancillary): Regulated by CERC or SERC under the Electricity Act 2003 for the power generation and sale activity. CEA technical standards and environmental standards apply to the power plant.

7.3.3 Audit Framework

Lead Framework: Mining audit — Chapter 9 leads for the overall entity.

Addendum Framework: GENCO audit — Chapter 8 or Chapter 10 (as appropriate for the technology) is added for the power plant component.

Specific audit points unique to this configuration:

(a) Separate Cost Accounting — Mandatory: Under the Companies (Cost Records and Audit) Rules 2014, both coal production and electricity generation are specified products/services. Each must have its own cost records and cost statements in the prescribed CRA-1 format. The cost auditor's report must separately address coal and electricity. Internal auditors must verify that no costs are cross-charged between the two activities without proper basis e.g. a coal company charging mining equipment maintenance to the power plant cost centre inflates power generation costs and deflates coal costs.

(b) Coal-to-Power Transfer Pricing: Where coal produced by the company is used as fuel for its own power plant, the price at which coal is transferred internally is a significant audit point. CERC may determine the input price; or the transfer may be at actual cost; or at market price. Whatever basis is used must be consistently applied and documented. An underpriced coal transfer reduces the coal business profitability and overstates the power plant's cost efficiency or vice versa.

(c) Dual Regulatory Compliance — Parallel Tracking: Both the mining regulatory submissions (DGMS; royalty; DMF; NMET) and the power regulatory submissions (CERC/SERC tariff; CEA data; environmental compliance for the plant) must be tracked simultaneously. A compliance calendar covering both dimensions must be maintained and verified quarterly by internal audit.

(d) Revenue Classification: Revenue from coal sales is the primary business revenue. Revenue from electricity sales is ancillary. The financial statements must correctly classify these. Under Ind AS 115, the revenue recognition policies for coal (commodity sale) and electricity (regulated tariff or market price) are different and must be applied separately.

(e) Cross-Subsidisation Risk: Where the coal business is profitable and the power business is making a loss or vice versa then there is a risk that management may allocate shared costs in ways that flatter the loss-making segment. Internal audit should examine shared cost allocation like management fees; infrastructure; administration; HR for reasonableness and consistency.

7.4 Pure Captive Power Plant — 100% Own Use

7.4.1 Configuration Description

A power plant set up by an industrial company like steel plant; cement plant; paper mill; chemical company; petrochemical refinery; or mine operator etc. to generate electricity exclusively for its own manufacturing or operational use, with no electricity sold to the grid or to third parties.

Examples: Captive power plants of Tata Steel Limited; JSW Steel; Ultratech Cement; ACC Limited; large coal mine operators powering mine operations; aluminium smelters with dedicated power plants etc.

7.4.2 The Captive Plant Definition — Section 2(8) of the Electricity Act 2003

A captive generating plant is defined under Section 2(8) of the Electricity Act 2003 as a power plant set up by any person to generate electricity primarily for own use. Rule 3 of the Electricity Rules 2005 specifies the conditions that must be satisfied for a plant to retain captive status: not less than 26% of the ownership must be held by the captive user or users; not less than 51% of the aggregate electricity generated, determined on an annual basis, must be consumed by the captive user or users; and where the plant is owned by an association of persons, each captive user must consume in proportion to its ownership, within a variation of 10%.

Failure to satisfy these conditions simultaneously and particularly the 51% consumption threshold results in the plant losing its captive status with immediate regulatory consequences.

7.4.3 What Makes This Configuration Fundamentally Different from a GENCO

The following comparison is essential for the internal auditor to understand before designing any audit programme for a captive plant:

Aspect	Pure Captive Plant	GENCO — Section 62 Regulated
Tariff regulation	None — power is an internal cost of production	CERC/SERC regulated tariff — external scrutiny
CERC/SERC compliance	Not required — no licence needed for 100% own use	Generation is de-licensed; tariff regulation applies to sale under Section 62
Tariff petition filing	Not required	Mandatory for each control period, with true-up
Power Purchase Agreement	Not required	Required for every MW sold
Scheduling with NLDC/RLDC	Not required	Mandatory — registered with RLDC
DSM (Deviation Settlement)	Not applicable	Applicable for all deviations
Capacity charges receivable	Not applicable	Receivable monthly from beneficiaries
PAF norm (CERC 85%)	Not applicable — no regulatory norm	Mandatory compliance; below norm = revenue loss
SHR norm (CERC 2340 SC)	Not applicable — but relevant for cost benchmarking	Mandatory compliance; above norm = tariff disallowance
BEE Designated Consumer	Applicable if threshold 30,000 toe/year is met	Applicable independently of captive/GENCO status
Open access charges	Applicable if drawing from grid in addition	Applicable when selling surplus on open access
RPO obligation	Applicable to captive consumption (MoP Order 2022; SERC regulations)	Not applicable to the generator — the obligation lies on the buyer
CEA technical standards	Applicable — safety; metering; construction	Applicable

7.4.4 Audit Framework

Lead Framework: Industrial company audit — the power plant is a cost centre within the industrial company. There is no separate regulatory framework for the power plant itself.

The power plant audit is therefore a **cost centre audit,** focused on cost efficiency, reliability, regulatory compliance (CEA; IBR; Factories Act / OSH Code; MoEFCC), and BEE compliance rather than a tariff audit.

Key audit points specific to pure captive plants:

(a) Cost Per Unit Generated vs Industry Benchmarks: Unlike a regulated GENCO where CERC norms provide the benchmark, the captive plant's performance is benchmarked against: BEE's

Designated Consumer benchmarks for the specific industrial sector; industry associations' published benchmarks; and the entity's own historical trend. SHR remains a meaningful efficiency indicator even without CERC applicability as high SHR in a captive plant directly increases the industrial company's energy cost.

(b) Fuel Cost and Procurement: Coal for a captive plant is procured through SHAKTI non-regulated sector linkage auctions, e-auction or imports, in line with the company's procurement policy. Verify: competitive procurement process; price benchmarking against market; GCV measurement and dispute management; fuel stock management; and consumption monitoring. Because linkage compensation for shortfall is limited, the company must build its own contractual protection against supply shortfalls.

(c) BEE Designated Consumer Status and PAT Compliance: If the plant crosses the threshold of 30,000 toe a year, verify DC registration and PAT compliance as set out in Section 13.8.

(d) CEA Technical Standards — Still Fully Applicable: The exemption from CERC/SERC regulation does not exempt a captive plant from CEA technical standards for construction; import requirements for power equipment (Section 5.4.6); metering regulations; and safety regulations. Verify CEA-prescribed metering at the boundary of the captive plant; IBR compliance for boilers; and annual electrical safety inspections etc.

(e) Open Access Charges When Drawing from Grid: When the captive plant is shut down for maintenance or cannot meet the full industrial load then the company draws electricity from the grid under open access. Verify: SERC open access compliance; cross-subsidy surcharge payment; wheeling charges; scheduling with SLDC; SERC charges computation etc. Where the industrial company is also selling surplus at other times, the open access compliance framework applies to both selling and buying.

(f) 51% Self-Consumption Ratio — Monthly Verification: Even a plant intended for 100% own use must check this ratio every month, as set out in Section 7.5.3(a), because occasional surplus sales can affect it.

7.5 Captive Power Plant with Partial Third-Party Sale

7.5.1 Configuration Description

A power plant that generates electricity for partly its own use and partly sells the surplus to the grid or to third parties. The most common scenario is an industrial company whose captive plant has surplus generation capacity that it sells on power exchanges or bilaterally.

Examples: Steel plant captive power plant selling surplus power to DISCOM or on IEX; cement plant with captive coal-based power plant selling surplus bilaterally; aluminium company selling surplus through power trader etc.

7.5.2 The Critical 51% Threshold — Two-Directional Audit Risk

If captive users consume less than 51% of the plant's generation in a year (Section 7.4.2), the plant loses captive status for that year. Power supplied to the former captive users is then treated as supply by a generating company, so cross-subsidy surcharge and additional surcharge become payable on it, together with SLDC scheduling, DSM obligations and the general power sector compliance framework. This threshold carries audit risk in both directions, and both are equally important.

Risk Direction 1 — Manipulation Upward (Inflating Own Consumption):

The company wants to retain captive status to avoid cross-subsidy surcharge and regulatory compliance costs. It may over-report its own consumption either by recording more units as "own use" than are actually consumed, or by reducing the denominator (total generation) by not recording all generation. The financial motivation is the cross-subsidy surcharge saving which can be substantial for large industrial consumers.

Detection procedure: Cross-verify own consumption meter readings against actual production records of the industrial unit; energy balance analysis like raw material consumed × energy consumption coefficient; compare with industry benchmarks for specific energy consumption; verify SLDC scheduling data against own consumption records etc.

Risk Direction 2 — Manipulation Downward (Deflating Own Consumption):

The company wants selling freedom at market prices without captive usage restrictions. Intentionally losing captive status may be commercially attractive if market prices are high. It may under-report own consumption or over-report generation to push the ratio below 51%. The motivation is commercial freedom.

Detection procedure: Same meter-level verification; energy balance; SLDC data comparison etc. The auditor should be alert to management explanations that systematically justify low own-consumption ratios without operational basis.

7.5.3 Audit Framework

Lead Framework: Depends on which portion is dominant.

- ✓ If own use is clearly dominant (above 70% of generation) — industrial company audit leads; third-party sale is an addendum
- ✓ If third-party sale is significant (above 30% of generation consistently) — GENCO audit framework applies to the selling portion as a concurrent lead; industrial company framework for the captive portion

Key audit points specific to this configuration:

(a) 51% Ratio — Monthly Tracking of an Annual Test: The legal test is applied on the annual figures, but the ratio should be tracked monthly so that management can act before the year closes and a shortfall becomes irreversible. Cross-check with SLDC scheduling data, which independently confirm the units sold to the grid.

(b) Dual Accounting Integrity: Internal cost accounting for the captive portion and revenue accounting for the third-party sale portion must be clearly segregated. Verify: correct allocation of fuel cost between captive and sold portions; correct revenue recognition for the sold portion under Ind AS 115; no cross-subsidisation between the two portions that distorts financial statements.

(c) Open Access Compliance for Third-Party Sale: Sales to consumers through open access attract SERC open access charges — transmission and wheeling charges, and cross-subsidy and additional surcharge payable by the buying consumer; sales to a DISCOM or on an exchange attract transmission charges and scheduling obligations. Verify correct charge computation, timely payment and compliance with the open access schedule.

(d) Cross-Subsidy Surcharge Exemption — Verify Eligibility: Captive users drawing power through open access are exempt from cross-subsidy surcharge only if the plant meets all three

captive conditions in Section 7.4.2. Verify each condition, because a plant that fails any one of them cannot claim the exemption.

(e) Related Party Sale Within Industrial Group: Where electricity is sold to group companies e.g., a parent company's captive plant sells to a subsidiary then the sale must be at arm's length pricing. Under Section 188 of the Companies Act 2013 and SEBI LODR for listed entities, RPT approvals are required. Additionally, SERC may examine whether group company transfers are genuine open access or merely an attempt to shift electricity cost between entities.

(f) GST on Intra-Group Sales: Electricity is exempt from GST (Section 5.10.1), including supplies to group entities. Verify that the exempt turnover is reported correctly and that input tax credit on common inputs is reversed under Rules 42 and 43 in proportion to the exempt supply.

7.6 Merchant Power Plant

7.6.1 Configuration Description

A generating station that sells electricity primarily in the short-term market either through power exchanges or bilateral arrangements without a long-term CERC/SERC regulated Power Purchase Agreement. The plant is not subject to CERC Section 62 tariff regulation. Revenue is entirely market-determined.

Examples: thermal IPPs selling on exchanges without long-term PPAs; gas-based plants without PPAs; older coal plants whose PPAs have expired.

7.6.2 What Makes This Fundamentally Different from a Section 62 GENCO

Aspect	Section 62 — Cost Plus	Section 63 — Competitive Bid	Merchant Plant
Tariff	Cost plus; tariff petition for the control period	Fixed at bid price for the PPA term	None; market prices
Prudency check	Full CERC/SERC scrutiny of costs	None; bid accepted at procurement	None
True-up	Periodic, per CERC/SERC regulations	Not applicable	Not applicable
Cost overrun	Recoverable only if necessary and prudent	Borne by developer	Borne by plant
Fuel cost risk	Largely passed through via FPA	Borne by developer above bid variable charge	Entirely borne by plant
Revenue	AFC + energy charges + FPA + incentive	Bid tariff × units delivered	Market price × units sold
Change of law	Cost increases potentially recoverable	Relief only for post-bid changes	Not applicable
Incentive	On scheduled energy above normative annual PLF (85%)	None beyond bid terms	None
Return	ROE 15.5% normative (CERC 2024-29)	Determined by bid	Determined by market
Revenue certainty	High for capacity charges; variable charges depend on performance	High once PPA signed	Low; price volatility

Grid code, scheduling, DSM, CEA standards	Apply	Apply	Apply

7.6.3 Audit Framework

The absence of tariff regulation fundamentally shifts the internal audit focus. For a Section 62 GENCO, internal audit devotes significant effort to tariff petition accuracy, prudency compliance, and cost documentation for regulatory scrutiny. For a merchant plant, none of this applies. Instead, the audit focus shifts to commercial decisions, cost efficiency, counter-party risk, and financial sustainability etc.

Key audit points specific to merchant power plants:

(a) Board-Approved Trading Policy: A merchant plant must have a Board-approved power sale policy covering: which market segments are permitted (DAM; RTM; TAM; bilateral; HP-DAM); minimum price thresholds below which the plant should not sell; approved counter-parties for bilateral sales; maximum exposure to any single counter-party; hedging policy if electricity derivatives are used. Verify policy existence; currency; compliance etc.

(b) Dispatch Economics — Running vs. Shut-Down Decision: A merchant plant should not run if the market price is below the variable cost of generation (primarily coal cost + auxiliary power cost + transportation). Verify: is there a Board-approved minimum variable cost threshold below which the plant shuts down? Are dispatch decisions documented? Is there evidence of running uneconomically like selling below variable cost for extended periods?

Systematic sale below variable cost may indicate: management incompetence; undisclosed related-party transactions (selling cheap to a related buyer); or fraud (skimming of the difference between cost and market price through a related trader).

(c) Exchange Settlement Reconciliation: Reconcile every DAM, RTM and TAM transaction with the exchange clearing settlement statements and bank credits (Section 13.3). Recognise revenue under Ind AS 115 only on delivery in the contracted time block.

(d) Fuel Cost Management — Critical Area: For a Section 62 GENCO, excess coal cost above normative SHR is largely recoverable through FPA. For a merchant plant, **there is no FPA mechanism**. Every rupee of excess coal cost above what was expected when the dispatch decision was made directly reduces margin. This makes GCV management, coal procurement strategy, and coal stock optimisation even more critical for a merchant plant than for a regulated GENCO. Audit coal cost per unit generated and compare against the market price received and the spread is the margin.

(e) Counter-Party Risk for Bilateral Sales: For bilateral sales, verify Board-approved counter-party limits, credit assessment before contracting, payment security (LC, advance or bank guarantee), and ageing of receivables; any sale to a counter-party beyond its approved limit or without security is a finding.

(f) Stranded Cost Risk — Ind AS 36 Impairment: Where exchange prices stay below variable cost for long periods, verify that an Ind AS 36 impairment assessment has been made on realistic price assumptions (Section 14.1.3).

(g) Electricity Derivatives Hedging: If the merchant plant uses electricity derivatives (traded on commodity exchanges under SEBI regulation) to hedge price risk then the Board approval is required; the hedging policy must specify permitted instruments, maximum hedge position, and effectiveness testing. Under Ind AS 109, hedge accounting requires formal documentation at inception. Verify: Board approval; hedging policy compliance; Ind AS 109 hedge accounting documentation and effectiveness testing.

(h) CERC Technical Compliance — Still Applies: The absence of tariff regulation does not mean the merchant plant is exempt from grid code; scheduling; DSM; and CEA technical standards. Verify: RLDC/SLDC registration; scheduling compliance; DSM settlement; CEA metering compliance. Technical non-compliance can result in penalties even without a tariff framework.

7.7 Ultra Mega Power Projects and Section 63 Plants

7.7.1 Configuration Description

Generating projects where tariff has been determined through competitive bidding under Section 63 of the Electricity Act 2003 rather than through cost-plus regulation under Section 62. This includes Ultra Mega Power Projects (UMPPs — 4,000 MW or more) and other projects procured through tariff-based competitive bidding (TBCB) by state DISCOMs or SECI.

Examples: Sasan UMPP (Reliance Power; 3,960 MW; Madhya Pradesh); Mundra UMPP (Coastal Gujarat Power Limited, Tata Power; 4,000 MW; Gujarat); Adani Power's Mundra and Tiroda plants, which supply state DISCOMs under Section 63 PPAs. Many recent renewable energy projects procured by SECI through reverse auction are also Section 63 projects.

7.7.2 Fundamental Difference from Section 62 Plants

See the comparison table in Section 7.6.2.

7.7.3 Audit Framework

The audit focus shifts in the same way as for merchant plants (Section 7.6.3): from tariff recovery to commercial decisions, cost efficiency, counter-party risk and financial sustainability.

Key audit points specific to Section 63 plants:

(a) Fixed Tariff Verification: Revenue = bid tariff per unit × units delivered under the PPA. Verify: correct tariff per the PPA; correct generation units certified by RLDC/SLDC; correct billing per beneficiary DISCOM allocation; timely billing; recovery tracking. Since the tariff follows the bid (escalating by CERC-notified indices where the bid has escalable components, and adjusted for change in law), any billing error is purely an arithmetic or documentation error but it can still be significant.

(b) Fuel Cost Management — Developer's Risk: The variable charge in a Section 63 bid was based on the bidder's assumption of coal price and SHR at the time of bidding. If actual coal cost is higher than assumed due to coal price increases; GCV shortfalls; or SHR deterioration then the entire excess is borne by the developer. This makes coal cost management a critically important internal audit area. Audit: GCV optimisation; coal blending strategy; import vs domestic coal mix; SHR improvement measures. The financial stakes of fuel inefficiency are far higher for a Section 63 plant than for a Section 62 GENCO.

(c) Change of Law Claims — Eligibility and Documentation: When a regulatory change after the bid date materially increases the cost of power generation, for example, a new environmental norm

requiring FGD installation that was not required at bid date; or a new coal cess levied after bid date then the developer is entitled to claim relief under the PPA's Change of Law provisions. Internal auditors must verify: the change occurred after the bid date; the change is a qualifying event under the PPA; the financial impact is correctly computed; the claim is filed with CERC or the SERC within the stipulated period; documentation is complete.

(d) PPA Compliance — Detailed Monitoring: The PPA is the primary commercial agreement and the source of all revenue. Non-compliance with PPA conditions can result in payment deductions; penalty clauses; or in extreme cases, termination. Verify: declared availability meets PPA-specified threshold; scheduling compliance; availability and generation data submitted to DISCOM as required; payment received within PPA timeline; LC/payment security maintained by DISCOM as required under the PPA and the MoP Standard Bidding Documents.

(e) Project Finance Covenant Compliance: Apply the project finance procedures in Section 10.7: DSRA, DSCR, Independent Engineer reports, Conditions Subsequent and events of default.

(f) SPV Governance: UMPPs and other Section 63 projects are usually SPVs. Apply Section 6.6.2, including arm's length pricing and Section 188 approval for sponsor–SPV transactions.

(g) Environmental Compliance: All environmental obligations apply exactly as for a Section 62 GENCO: FGD by plant category, CEMS, ash utilisation and water (Section 8.4).

7.8 Washery and By-Product Power Plants

7.8.1 Configuration Description

Power plants that generate electricity from coal rejects; middlings; or mine gas (methane), the by-products of coal washing operations or mine gas extraction. The power plant is ancillary to the washery or mine operation.

Examples: Coal washery power plants using middlings and rejects from coal washing; mine gas-based power plants using extracted methane at underground coal mines; waste heat recovery power plants at coking coal processing facilities.

7.8.2 What Makes This Configuration Unique

The fuel (middlings, rejects or mine gas) has near-zero or negative value, since it is waste that would otherwise need disposal. The plant's variable cost is therefore almost entirely operating cost, and power revenue is largely margin. The configuration sits under three oversight regimes. First, MoC/CCO monitors the washery material balance, to ensure coal is not misdeclared as rejects. Second, the generating unit carries standard compliance: CEA standards, IBR, CERC/SERC tariff where power is sold under a regulated PPA, and environmental consents. Third, for mine gas, PESO regulates extraction, handling and use.

7.8.3 Audit Framework

Lead Framework: Mining/washery audit — Chapter 9 leads for the overall entity.

Addendum: Power plant audit — Chapter 8 for coal reject/middlings-based power; applicable SERC framework for power sold under regulated tariff.

Key audit points specific to washery and by-product power plants:

(a) Fuel Valuation and Transfer Pricing: What is the value at which middlings or rejects are transferred from the washery to the power plant? If both washery and power plant are within the

same entity then the transfer price determines the cost of generation in the power plant's books and affects the washery's profitability. If transferred at zero value then the power plant shows near-zero fuel cost and very high margin. If transferred at an assessed market value then the washery shows higher revenue and the power plant shows higher fuel cost. The basis must be documented; consistently applied; and approved by management. CERC may specify the fuel valuation basis if the power is sold under regulated tariff.

(b) Washery Material Balance Verification: Obtain the MoC/CCO-approved yields of washed coal, middlings and rejects. Compare them, and the Coal Dispatch Annual Returns, with weighbridge data for each product stream. Unexplained differences may indicate washed coal misclassified as rejects, diversion, or measurement fraud.

(c) Revenue and Cost Classification — Separate Cost Centres: Classify revenue from washed coal, power and other products separately. Each needs its own cost statements under the Cost Records Rules, and shared costs must be allocated on a documented basis (see Section 7.3.3(a)).

(d) Mine Gas Power Plant — PESO and Safety Compliance: Verify: PESO licence for mine gas extraction and utilisation — validity; conditions; quantities authorised; gas measurement equipment calibration; explosion-proof equipment certification for gas-handling areas; gas flow meters — calibration; PESO-approved meters only; methane dehydration system operational status; emergency shutdown systems tested; DGMS approval for methane drainage scheme.

(e) Carbon Credit Eligibility: Generation from coal rejects, middlings or mine methane is not renewable and does not qualify for RECs. Capture and use of mine methane may qualify for carbon credits under the CCTS offset mechanism or Article 6 where an approved methodology exists; verify eligibility, the MRV plan, the validator's report and the registry entries (Sections 13.9 and 13.10).

7.9 Hybrid RE Plus Storage Plants

7.9.1 Configuration Description

A single project or entity that combines multiple generation technologies like solar plus wind; RE plus Battery Energy Storage System (BESS); RE plus diesel backup; RE plus gas peaking plant etc. under a single tariff or PPA structure. Hybrid projects are increasingly the standard for new large-scale RE procurement in India as the sector seeks to address the intermittency limitations of individual RE technologies.

Examples: Solar plus BESS projects tendered by SECI under Round-the-Clock (RTC) RE framework; wind plus BESS projects; solar plus wind plus BESS hybrid projects; SECI tenders with 70% RE + 30% storage specifications; state DISCOM procurement of firm power from hybrid RE etc.

7.9.2 What Makes This Configuration Complex

Each technology has its own metric. Solar uses CUF (19–22%) and PR (above 80%); wind uses turbine availability (above the 97% OEM guarantee) and PLF (25–35%); BESS uses round-trip efficiency (85–92% for Li-ion) and state of charge. Applying a single metric to the whole project gives meaningless results. The combined resource is scheduled to the grid as one entity, but the internal dispatch (when to charge, discharge or curtail) must follow the PPA's technical specifications. PPA structures differ: some pay a single blended tariff for all units, others a separate tariff per technology. Many SECI projects also carry a Round-the-Clock (RTC) supply obligation, with penalties for shortfall.

7.9.3 Audit Framework

Lead Framework: RE GENCO framework — Chapter 10 leads for all components including RE and BESS.

Key audit points specific to hybrid RE plus storage projects:

(a) Technology-Wise Audit Then Consolidation: Audit solar (Section 10.2), wind (Section 10.3) and BESS (Section 10.5) separately, each with its own metrics, then consolidate. Under-performance in one component, such as solar CUF below guarantee, can be masked when BESS compensates. This matters for OEM warranty claims and PPA penalties.

(b) Despatch Compliance with PPA Specifications: Obtain the despatch log from the energy management system and verify that charging, discharging and curtailment follow the PPA's technical specifications. Systematic deviation may indicate control-system faults, or manipulation at the cost of grid stability.

(c) Independent Metering for BESS Charging Source: Only energy discharged from a BESS charged by the project's RE component carries the RE attribute. Grid-charged energy does not, and only the RE portion counts towards RPO (including ESO). Separate metering of RE and grid charging is therefore mandatory: verify the meters, their calibration, and reconciliation with BMS logs (Section 10.5.2, Step 3). Without separate metering, REC eligibility cannot be established, which is a fundamental audit finding.

(d) BESS Performance — Parameters: monthly RTE, annual degradation against the OEM warranty, SoC within 10–90%, and fire safety.

(e) Tariff Structure: Verify that billing follows the PPA's tariff structure, blended or per technology, without mixing regimes in one invoice.

(f) RTC Obligation Compliance Monitoring: Monitor monthly the hours supplied against hours required, shortfall hours by cause (grid unavailability is typically force majeure), penalty computation and corrective action. Report to the Audit Committee if penalty exposure exceeds materiality.

(g) Diesel or Gas Backup: Where backup is present, audit fuel consumption and emissions. Verify that backup generation is not reported as RE and does not jeopardise the project's RE certification.

(h) Project Finance Compliance: Apply Section 10.7: DSRA, DSCR, IE reports and Conditions Subsequent. The lenders' Independent Engineer is a valuable independent technical source for multi-technology projects.

7.10 Summary Decision Matrix — Quick Reference

The following table provides the internal auditor with a quick-reference guide for each of the eight configurations covered in this chapter. Before commencing any audit, confirm which row applies to the entity being audited.

Configuration	Lead Framework	Addendum Framework	Key Unique Audit Point Not Covered in Standard Framework
GENCO with captive coal mine (Integrated GENCO)	Chapter 8 — Thermal GENCO	Chapter 9 — Mine Audit	Coal transfer pricing at CERC/SERC-determined mine input price; dual EC tracking; separate cost centres

Configuration	Lead Framework	Addendum Framework	Key Unique Audit Point Not Covered in Standard Framework
Coal company with power plant	Chapter 9 — Mine Audit	Chapter 8 or Ch.10 — GENCO Audit	Separate cost centres mandatory; dual regulatory compliance calendar; revenue classification coal vs electricity
Pure captive plant — 100% own use	Industrial company audit — power plant as cost centre	None from this GN	51% self-consumption ratio monthly; BEE/PAT Designated Consumer compliance; CEA technical standards still apply; no CERC tariff framework
Captive plant with partial third-party sale	Depends on dominant portion — industrial or GENCO	Chapter 8 or Ch.13 for selling portion	Two-directional manipulation risk of 51% ratio; dual accounting separation; ITC reversal on exempt electricity sales; open access compliance
Merchant power plant	Chapter 8 — Thermal GENCO (operational procedures)	Chapter 13 for exchange participation	Board trading policy; dispatch economics vs variable cost; no FPA pass-through; stranded cost risk Ind AS 36; electricity derivatives hedge accounting
Section 63 / UMPP	Chapter 8 — Thermal GENCO (operational procedures)	None for tariff — no tariff petition or true-up	Fixed tariff audit; fuel cost entirely developer's risk; change of law claims eligibility; PPA compliance detailed monitoring; project finance DSRA/DSCR/IE reports
Washery and by-product power plant	Chapter 9 — Mine/Washery Audit	Chapter 8 for power plant component	Fuel valuation transfer pricing washery to power plant; washery material balance MoC compliance; PESO licence for mine gas; carbon credit eligibility for mine methane
Hybrid RE plus storage	Chapter 10 — RE GENCO Audit	None — all components within Ch.10	Technology-wise audit then consolidation; despatch compliance with PPA; independent BESS charging source metering mandatory; RTC obligation monitoring; BESS charging source determines REC eligibility

8. GENCO AUDIT — THERMAL POWER PLANTS

8.0 Introduction

Thermal power plants — coal-based, gas-based, and oil-based remain the backbone of India's electricity supply. Despite the rapid growth of renewable energy, thermal generation contributed approximately 75% of total electricity generated in India in 2024-25. For internal auditors, thermal GENCO audit is both the most material and the most complex segment of power sector audit, involving fuel management, plant operations, environmental compliance, regulatory tariff, capital works, and procurement, each of which carries significant financial risk.

This chapter covers the complete internal audit framework for thermal generating companies regulated under Section 62 of the Electricity Act 2003. The chapter is organised by financial materiality like fuel management first, followed by plant operations KPIs, environmental compliance, tariff petition pre-filing audit, capital works, and gas-based plant specifics etc. Each section identifies what to audit, the applicable norm or standard, specific step-by-step audit procedures, red flags, and financial impact quantification.

Where a thermal GENCO also operates a captive coal mine, this chapter covers the power plant audit. Mine-specific audit is covered in Chapter 9. The coal-to-plant interface particularly transfer pricing is covered in Section 7.2.

For Section 63 competitive bid plants and merchant plants, the operational audit procedures in this chapter apply in full. The tariff-specific sections like Section 8.5 (pre-filing audit) do not apply to those configurations. Refer Sections 7.6 and 7.7 for the configuration-specific differences.

8.1 Red Flag Dashboard — Thermal GENCO

The following ten indicators provide a quick assessment of potential control problems at a thermal generating station. The internal auditor should evaluate all ten at the commencement of every audit cycle before commencing detailed procedures. A single red flag does not confirm a problem; it directs audit focus.

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
1	Coal stock below the applicable CEA norm	Month-end stock (days) below the CEA norm for the plant	Fuel security risk; regulatory scrutiny; potential forced shutdown
2	PAF below normative level	Below 85% for two or more consecutive months	Capacity charge revenue loss; forced outage investigation needed
3	SHR above CERC norm	More than 5% above normative SHR for the unit type	Excess coal consumption; investigate GCV and boiler efficiency
4	SOC above CERC norm	More than 3x normative 0.30 ml/kWh	Excessive oil firing; boiler condition concern; manipulation risk
5	FPA not raised for more than 2 months	Two consecutive months without FPA invoice to any beneficiary	Revenue leakage; billing process breakdown
6	Capital works cost overrun above 15%	Cost overrun above 15% of Board-approved estimate	Regulatory prudence-check/disallowance risk; contract management failure

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
7	CEMS data gaps above 5% in a month	OCEMS portal showing above 5% data unavailability	Environmental violation; data manipulation risk
8	Ash utilisation below 80%	Annual fly ash utilisation below 80%	CPCB non-compliance; Fly ash utilisation report (CPCB portal) accuracy risk
9	CAG or CERC paras pending beyond 3 years	Any para unresolved beyond 3 years	Governance failure; Audit Committee escalation required
10	Major insurance policy lapsed	Any generation loss; breakdown; or property policy lapsed	Significant financial exposure in event of breakdown or accident

8.2 Fuel — Coal Management Audit

8.2.1 Fuel Supply Agreement Compliance Audit

The Fuel Supply Agreement (FSA) with the CIL subsidiary or SCCL is the primary contractual document governing coal supply. FSA compliance is a material and ongoing audit obligation.

Documents to obtain: FSA — current and previous years; SHAKTI Letter of Assurance (LoA); monthly coal supply statements from coal company; ACQ performance reports; penalty claim correspondence; LoA Bank Guarantee copy, GCV Adjustment reconciliation statements etc.

Step 1 — ACQ Tracking: Extract month-wise coal receipt data from the entity's coal management system or stores records. Compare actual receipts against the contracted ACQ in the FSA on a month-wise and cumulative basis. Generally, supply below 90% of the monthly ACQ triggers escalation to coal company management, whereas supply below 75% of the monthly ACQ triggers the graded penalty mechanism under the FSA.

Step 2 — Shortfall Penalty Billing: Where the coal company (CIL subsidiary or SCCL) has supplied less than 75% ACQ without a declared force majeure, the FSA's graded penalty provisions are triggered. Verify: whether the GENCO has computed the penalty correctly using the FSA formula; whether penalty bills have been raised on the CIL subsidiary; track recovery status — amounts raised; amounts received; amounts disputed; amounts pending. Penalty bills not raised within the stipulated period may become time-barred. Financial impact = (Trigger level quantity for the assessment period, e.g. 75% of ACQ − Actual supply) × compensation rate per tonne under the FSA.

Step 3 — SHAKTI LoA Compliance: Verify, as applicable: validity and compliance with LoA/FSA/linkage-allocation conditions; fulfilment of prescribed milestones; Bank Guarantee — amount, validity and timely renewal; end-use and other prescribed certifications; coal drawal against ACQ/allocated quantity, including applicable minimum drawal obligations; and compliance with other conditions of the relevant SHAKTI allocation/linkage mechanism.

Step 4 — FSA Amendment and Variation: For any amendment to ACQ, GCV band, price basis or delivery terms, verify that a formal amendment was executed, that Board approval was obtained for material changes, and that the financial implications were assessed and documented.

Red Flags: ACQ shortfall not being tracked in any systematic register — organisation has no visibility of its entitlement shortfall; LoA Bank Guarantee not renewed — LoA will lapse; same party consistently winning e-auction coal from the same mine — collusion risk; FSA amendment increasing the GCV band without corresponding price reduction — financially adverse to GENCO.

8.2.2 Coal GCV Audit

GCV is the single most disputed parameter in coal supply and the most financially significant. An incorrect GCV measurement directly affects fuel cost; FPA billing to beneficiaries; and CERC true-up adjustments. GCV disputes can involve hundreds of crores annually for a large generating station.

Documents to obtain: Third-party sampling reports at loading point — CIMFR or another third-party agency appointed under the FSA; destination sampling reports at plant; GCV dispute correspondence with CIL/SCCL; FSA GCV band specification; CIL/SCCL monthly price notification linked to GCV band; CIMFR empanelment certificate.

Step 1 — GCV Measurement Process Verification: Verify that the third-party sampler at the loading point is CIMFR or another third-party agency appointed under the FSA for this purpose. Verify the sampling agency's independence — no financial relationship with the coal company beyond the sampling contract; no undisclosed related-party connection. Verify sampling protocol — sample size per rake; frequency; sample preparation; chain-of-custody documentation; dispatch to laboratory; laboratory turnaround time. Cross-verify: average GCV declared by third-party sampler at loading point against average GCV from destination sampling at the plant — systematic downward difference at destination warrants investigation.

Step 2 — GCV-Based Billing Reconciliation: Extract FSA coal bills received from CIL/SCCL for the audit period. Verify that each bill applies the correct GCV-linked price band as specified in the FSA and relevant Price Notification, wherever applicable. Reconcile the GCV declared by the coal company in its bill against the GCV determined by the third-party sampling report for the same rake. Where the coal company's declared GCV is higher than the third-party sampling result, the difference must be adjusted through a credit note from the coal company; where it is lower, a debit note.

Step 3 — GCV Dispute Management: Verify that GCV disputes are filed with the coal company within 45 days of receiving the third-party sampling report, generally this is the typical contractual deadline beyond which disputes become time-barred. Create a dispute tracker: month of sample; rake details; third-party GCV; coal company's declared GCV; shortfall per tonne; total shortfall tonnes; estimated financial impact; date dispute filed; coal company response; status — settled/pending/rejected/under arbitration; accounting treatment of disputed amount. Where disputes have been settled in the GENCO's favour — verify credit note or refund received and correctly accounted.

Step 4 — GCV Impact on CERC True-Up: Verify the GCV of coal as billed by the supplier against the GCV as received at the generating station. Under the CERC tariff framework, Energy Charge Rate is computed using the weighted-average GCV of coal as received, after the prescribed storage adjustment. Identify grade/GCV slippages, raise claims against the coal supplier in accordance with the FSA/contract, and track their recovery. Quantify the financial impact of unresolved GCV/grade disputes based on the difference between the amount paid for the coal supplied and the amount payable for the established grade/quality, as applicable.

Step 5 — Coal Grade Slippage: Verify that the grade of coal actually supplied corresponds to the grade specified in the FSA. Grade slip — supply of lower grade coal than contracted is common. Grade determines FSA price band; grade slippage with inadequate GCV-based billing correction results in the GENCO paying the G9 price for G11 coal, for example. Verify grade on coal company invoice against third-party sampling result.

Red Flags: no GCV disputes raised despite a systematic shortfall, suggesting complacency or an undisclosed arrangement with the coal company; the third-party sampler changed frequently without documented reasons.

Financial Impact Formula: Refer Appendix A12.1.

8.2.3 Coal Stock Management Audit

CEA's coal stocking norms prescribe a minimum coal stock for each plant according to its distance from the source mine. Consistently falling below the applicable norm indicates operational risk and creates financial exposure.

Step 1 — Theoretical vs Physical Stock Reconciliation: The theoretical closing coal stock formula is: Opening Stock + Receipts − Consumption = Theoretical Closing Stock. Compare theoretical closing stock with physical stock as per last physical measurement. An acceptable variance is normally within 2-3% due to moisture loss and stacking losses. Significant variance like above 5% requires investigation for possible pilferage; measurement fraud; recording errors; or spontaneous combustion losses.

Step 2 — Coal Stock in Days against CEA Norm: Normative daily consumption (tonnes) = Installed capacity in MW × 24 hours × 85% PAF × Normative SHR in Kcal/kWh ÷ GCV in Kcal/kg. Coal stock in days = Actual physical stock in tonnes ÷ Normative daily consumption. Track month-end coal stock in days for the entire audit period. Persistent shortfall below the applicable CEA norm particularly during lean coal supply months requires investigation and constitutes a Red Flag.

Step 3 — Physical Verification Methodology: Coal stock is measured volumetrically — area × average height × bulk density of coal. Bulk density varies with coal type; moisture content; and degree of compaction. Verify: bulk density value used is appropriate and documented; survey is conducted by qualified surveying personnel; measurements taken in presence of both stores and finance representatives; last physical verification date and by whom. Conduct a surprise physical stock count during the audit without advance notice to stores and reconcile with book records.

Step 4 — Coal Quality Deterioration in Stock: Coal stored for extended periods deteriorates in quality i.e. GCV reduces due to oxidation and moisture gain. Verify: FIFO (First In First Out) basis of consumption; no coal remaining in stock beyond 60 days without testing for GCV; spontaneous combustion monitoring — temperature probes; fire-fighting equipment at coal yard; water sprinklers functional. Coal yard drainage particularly post-monsoon to prevent coal quality deterioration from water absorption.

Red Flags: Physical stock significantly lower than book stock by more than 5% — pilferage or measurement fraud; bulk density applied inconsistently across surveys with no documentation of basis; coal stacked beyond 7-metre height — CEA/safety guidelines; FIFO not followed — oldest coal remaining in stock for months.

Financial Impact Formula: Refer Appendix A12.1.

8.2.4 Coal Transportation Audit — Rail

Step 1 — Rake Supply vs Tripartite Commitment: Monthly rake supply received vs rake supply committed under the tripartite agreement between GENCO; coal company; and Indian Railways. Any shortfall — has the GENCO formally taken up the shortfall with Railways and the coal company? Track cumulative rake supply vs commitment month-wise.

Step 2 — Railway Freight Verification: Railway freight tariff — verify correct distance between loading siding and plant siding; correct classification of coal as bulk commodity; correct wagon type used. Freight per tonne reconciliation — compute applicable freight as per the Railway tariff circular and compare with actual freight billed. Any excess freight charged must be recovered. Demurrage and wharfage — wagon detention beyond free time attracts demurrage; verify computation against Railway rules; minimise by maintaining adequate wagon unloading capacity; Verify whether idle freight, penal freight and other charges billed by Railways are recoverable from the coal company under the FSA, and whether they have been recovered.

Step 3 — Shortage Claims: Transit shortage = loading weight per rake − unloading weight at plant. Normative transit loss is recognised by CERC. Where shortage exceeds the normative loss, a claim must be filed with Railways within 6 months of rake delivery. Verify: shortage claims filed within 6-month deadline for all rakes showing shortage above normative; claim documentation — weigh-bridge certificate at plant; RR weight at loading; shortage certificate; track recovery status. Insurance claim for shortage above a specified threshold — verify timely lodgement.

Step 4 — Railway Siding Maintenance: The railway siding at the power plant end is the GENCO's responsibility to maintain. Verify maintenance contract — competitive tendering; contractor performance; any speed restrictions imposed by Railways due to siding condition; impact of speed restriction on daily unloading capacity and coal stock build-up.

Red Flags: Transit shortage consistently above normative for several rakes without claims being filed; shortage claims not filed within 6-month deadline — time-barred; freight bills paid without verification against Railway tariff circular; railway siding under speed restriction affecting coal receipt.

8.2.5 Coal Transportation Audit — Road

Road coal transport is the highest-fraud-risk area in fuel management. The opportunity for manipulation is greatest at the weighbridge and in the trip records.

Step 1 — Weighbridge Fraud Detection: This is one of the most material and most prevalent fraud areas in thermal power plant operations. The following procedures are mandatory for all thermal GENCO audits:

Weighbridge calibration: Verify last calibration date — Legal Metrology Act 2009 requires periodic calibration by a certified agency; certificate must be current. Verify calibration was performed by a certified agency under the Legal Metrology (General) Rules 2011.

CCTV coverage: Verify CCTV cameras cover the entire weighbridge — approach; platform; exit with no blind spots. CCTV recording must be continuous; storage must be minimum 90 days; access to recording must be restricted to authorised personnel only with access log maintained. Pull random CCTV footage for cross-verification during audit.

Weighbridge software audit trail: Access the weighbridge software and verify who has administrative access; when was software last modified; is there an audit trail of all weighments; are manual overrides recorded and logged; have any weighments been deleted or modified after initial recording. Software manipulation, typically a table in the database that can be edited is the most common and most difficult to detect form of weighbridge fraud.

Tare weight verification: Each truck's registered tare (empty weight) must be periodically re-verified. Inflating the registered tare weight of a truck reduces the computed net coal weight on every load — systematic under-reporting. Conduct spot checks by independently weighing a sample of coal trucks empty and comparing against registered tare.

Second weighment: Arrange surprise second weighment of loaded trucks at an independent weighbridge either at another point within the plant or by engaging a third party. Systematic difference between first and second weighment is evidence of calibration manipulation or software fraud.

Driver-operator nexus indicators: Check records for same driver delivering multiple loads within physically impossible timeframes; after-hours deliveries without management approval; consistent delivery of the same quantity on every trip — natural variation should exist.

Step 2 — Transport Contract Compliance: Rate per tonne — verify competitive bidding process; Board/DFP approval; rate benchmarking against prevailing market rates; Quantity reconciliation — differences between loading-point and unloading quantities beyond the contractual tolerance, and recoveries made for them; distance verification — actual mine-to-plant road distance vs claimed distance. Vehicle fitness — each transport contractor vehicle must have valid fitness certificate; PUC certificate; GPS tracker installed and transmitting. GPS data — pull GPS data for all trips; identify route deviations from contracted mine to plant; any GPS jamming episodes; verify loading point is the contracted mine location.

Step 3 — Environmental Compliance: NGT directions mandate tarpaulin covers on coal trucks to prevent dust pollution. Verify photographic or CCTV evidence of tarpaulin compliance; watering of approach roads; dust suppression at unloading point; any SPCB complaints relating to coal truck pollution.

Red Flags: Weighbridge calibration certificate expired or from non-certified agency; CCTV not continuously recording or storage below 90 days; software administrative access not logged; same net weight recorded for multiple consecutive trucks — statistically improbable; GPS route deviations showing loading from location other than contracted mine; tare weight of trucks decreasing progressively over months.

8.2.6 Imported Coal Audit

Where a thermal GENCO imports coal to supplement domestic coal supply, the import process involves procurement, customs, FEMA, and transfer pricing dimensions.

Documents to obtain: Import contracts; Bills of Lading; Import Bills of Entry; Draft survey/displacement survey reports at discharge port; GCV analysis reports at load port and discharge port; Letters of Credit; FEMA remittance documents; Customs duty payment receipts.

Step 1 — Procurement Process: Global tender or limited inquiry — verify Board-approved procurement policy for import coal; price competitiveness — compare import price (CIF) against prevailing market benchmarks such as Newcastle thermal coal index or Indonesia HBA index

applicable for the GCV and sulphur specification of the imported coal; quantity and quality specification — GCV band; ash content; moisture; sulphur limits; supplier financial assessment for advance payment security.

Step 2 — Customs and Duty Compliance: HSN Code — thermal coal is classified under HSN 2701; verify correct sub-heading; Basic Customs Duty (BCD) rate applicable at time of import; Agriculture Infrastructure and Development Cess (AIDC); Social Welfare Surcharge (SWS) — total customs duty computation; IGST on import at 18% on coal — ITC claim in GSTR-3B; Bill of Entry — verify duty computation; CIF value as assessed; payment of duty within due date; any duty exemption claimed — end-use certificate conditions; post-import verification obligations.

Step 3 — FEMA Compliance: Verify that LCs are opened through an authorised dealer bank on terms consistent with the contract and UCP 600; that advance payments follow RBI time limits; and that import payables are hedged under the Board-approved policy, with Ind AS 109 documentation (Sections 5.15.1 and 14.2.2).

Step 4 — GCV and Quantity Verification at Port: GCV at load port (per survey report) vs GCV at discharge port — systematic downward difference indicates possible transit coal mixing or load port GCV over-certification. Draft survey at discharge port — independent surveyor; methodology; result compared to Bill of Lading quantity; shortage claim against shipping company if quantity below Bill of Lading weight beyond permissible tolerance.

Step 5 — Transfer Pricing for Related Party Imports: Where coal is imported through a related trading entity, verify arm's length pricing against an independent benchmark at the contract date, the transfer pricing report, and CbCR where group revenue exceeds Rs. 5,500 crore (Section 5.9.1). Related-party coal imports are also a recurring DGGI audit target.

Red Flags: Import price significantly above prevailing market benchmark without documented technical justification such as premium sulphur specification; related party import without transfer pricing documentation and Form No. 48; GCV at load port significantly higher than GCV at plant — transit mixing or load port sampling manipulation; duty exemption claimed without completed end-use certificate.

8.2.7 Fuel Price Adjustment Computation and Billing

For central stations, the Energy Charge Rate under the CERC Tariff Regulations 2024-29 is computed monthly on the weighted average landed price of fuel and the GCV as received, so fuel cost variations pass through automatically; for state GENCOs, SERC regulations provide a Fuel Price Adjustment (FPA) or Fuel Cost Adjustment formula.

Step 1 — FPA Formula Application: Under the applicable SERC regulations, FPA is typically computed as (Actual variable cost − Normative variable cost) × Actual generation in kWh. Where Normative variable cost = Normative SHR in Kcal/kWh × Normative fuel price at normative GCV. Verify that the monthly energy charge or FPA computation uses the formula in the applicable CERC or SERC regulations, the correct landed price, and the correct GCV basis.

Step 2 — Computation Accuracy: Actual coal consumption per unit of generation — reconcile with station coal consumption records; actual GCV used in FPA computation must match the GCV as per third-party sampling certificate for that month; weighted average coal price — weighted average of: FSA coal at applicable GCV-linked price; e-auction coal at purchase price; imported coal

at landed cost — weighted by quantities. Any computation error — quantify financial impact; raise correction invoice immediately.

Step 3 — Billing and Recovery: FPA must be billed to each beneficiary in proportion to their contracted share within 30 days of the month end. Track FPA billing timeliness; recovery aging — amounts billed; amounts received; amounts overdue; interest on delayed payment beyond the PPA-specified free period; where payment is delayed beyond 45 days — payment security mechanism under PPA terms should be invoked; LC encashment or escrow drawdown as provided in the PPA.

Red Flags: FPA not raised for two or more consecutive months — revenue leakage; FPA bills not recovered within 45 days and no payment security invoked — remedies available under PPA arbitration clause or adjudication by CERC under Section 79(1)(f) or the SERC under Section 86(1)(f) of Electricity Act, 2003.

8.3 Plant Operations KPI Audit

8.3.1 Overview of KPI Framework

CERC prescribes normative values for key operational parameters under the Tariff Regulations 2024-29. These norms determine: capacity charge entitlement — linked to PAF; energy charge recovery based on normative SHR and normative fuel price; incentive entitlement for scheduled energy above the normative annual PLF; and deviation settlement where actual generation differs from the schedule.

Internal audit verifies that actual performance is accurately measured, correctly reported to CERC, and that significant deviation from norms is investigated for root cause and corrective action. Manipulation of KPI data to improve tariff recovery — while actual performance is below norm is one of the most serious fraud risks in thermal GENCO audit.

8.3.2 Plant Availability Factor (PAF) Audit

Applicable Norm: 85% for thermal stations under CERC 2024-29 Regulations. The PAF determines capacity charge entitlement: below 85%, capacity charge is reduced pro rata; at or above 85%, full capacity charge is recovered. Incentive is not linked to PAF. It is payable on scheduled energy above the normative annual PLF, at the rates specified in the Regulations for peak and off-peak hours.

Formula: PAF% = (Sum of available MW-hours during the period ÷ (Installed capacity MW × Total hours in period)) × 100.

Step 1 — Outage Classification Verification: PAF manipulation through outage misclassification is the most commonly found fraud in power sector regulatory audit. An outage classified as "grid constraint" or "backing-down by SLDC" which does not reduce PAF instead of "forced outage due to equipment failure" which does reduce PAF — artificially inflates reported PAF while the plant is actually not available.

Obtain the unit-wise outage log for the entire audit period — date-wise; reason code; duration; MW unavailable. For every outage classified as "grid constraint" or "backing-down" — verify a corresponding written instruction from SLDC/RLDC to back down on that date and time. If no such instruction exists in writing from SLDC/RLDC, the classification is suspect. Verify that backing-down instructions are in the format prescribed by CERC as they cannot be verbal.

Cross-verify against physical maintenance work orders — if maintenance work was carried out on the unit during a period classified as "grid constraint," the unit was clearly in a forced outage, not backed down by the grid. Equipment repair records; purchase orders for emergency spares; and contractor invoices for breakdown repairs are independent evidence of forced outage.

Step 2 — SCADA Data Cross-Verification: Extract the unit-wise generation data from the SCADA historian for the audit period. Compare SCADA-recorded actual generation against the generation data submitted to RLDC/SLDC and reported to CERC. Significant and systematic difference between SCADA actual and reported figures is a strong indicator of data manipulation. SCADA historians are difficult to manipulate retrospectively making them the most reliable source for cross-verification.

Step 3 — PAF Impact on Capacity Charges: Compute the financial impact of actual PAF vs normative PAF: Annual capacity charge loss = Annual Fixed Charges × (Normative PAF − Actual PAF) ÷ Normative PAF.

Red Flags: Outage reason codes heavily skewed toward grid constraint without corresponding SLDC/RLDC instructions; forced outages reported consistently for very short durations such as 30 minutes or 1 hour — suggests under-reporting of actual duration; PAF reported at exactly 85.00% every single month — statistically improbable; SCADA generation data lower than reported generation data. Refer Appendix 1.

8.3.3 Station Heat Rate (SHR) Audit

Applicable Norm: 2,340 Kcal/kWh for supercritical 500 MW units under CERC 2024-29. Different norms apply for different unit sizes and technologies — refer Appendix 1 for the complete CERC 2024-29 KPI parameters table.

Formula: SHR = Total heat input in Kcal ÷ **Gross** generation in kWh.

Step 1 — Monthly SHR Computation Verification: Obtain monthly SHR computation for each unit and for the station overall. Verify heat input computation: heat input = coal consumed in tonnes × GCV in Kcal/kg × 1,000. Critically — verify that the GCV used in the SHR computation is the plant's as-received (or as-fired) GCV from its own sampling, and that the difference from the billed GCV at the loading end is explained by the transit and storage allowance; an unexplained or changing basis is a strong indicator of data manipulation. Verify the generation figure — gross generation at the generator terminals as metered, reconciled to the RLDC/SLDC-certified ex-bus figure through auxiliary consumption (Section 8.3.4).

Step 2 — Root Cause Analysis for High SHR: High SHR can arise from multiple causes. Internal audit must investigate root cause because the audit recommendation differs depending on cause:

Root Cause	Indicator	Audit Action
Low coal GCV	Actual GCV below FSA grade	Verify GCV dispute filed; FPA impact computed
Poor boiler efficiency	High unburnt carbon in ash; low boiler efficiency test result	Verify R&M plan; boiler tube inspection records
Mill performance	High mill rejects; coarse coal fineness	Verify mill maintenance records; grinding ring condition

Root Cause	Indicator	Audit Action
Part-load operation	Frequent SLDC backing-down	Cross-verify with SLDC instructions; check SCED compliance
Ageing equipment	Progressive SHR deterioration year-on-year	Verify residual life assessment; R&M plan; CERC recognition
Condenser fouling	High condenser back pressure; high cooling water temperature differential	Verify condenser tube inspection; online tube cleaning system
Auxiliary systems	High fan power; poor air-fuel ratio	Verify ESP; fan; pump maintenance records

Step 3 — Financial Impact: Excess coal consumption: (Actual SHR − Normative SHR) × Gross generation kWh ÷ 1,000,000 ÷ GCV in Kcal/kg × 1,000 = Excess coal in tonnes. Financial impact = Excess coal tonnes × Weighted average coal price. Additionally — excess coal consumption above normative SHR is not recoverable through FPA; it is a permanent cost to the GENCO.

Red Flags: SHR reported to CERC different from SHR in internal plant performance records; GCV used in SHR computation different from GCV in coal quality certificates; SHR improving steadily every month in the months approaching CERC true-up period without any corresponding operational improvement. Refer Appendix 1.

8.3.4 Auxiliary Power Consumption (APC) Audit

Applicable Norm: Unit-specific as per CERC 2024-29 Regulations — supercritical units have lower normative APC than sub-critical units. Refer Appendix 1.

Formula: APC% = (Gross generation − Net generation) ÷ Gross generation × 100.

Step 1 — APC Sub-Component Analysis: Break down APC into sub-components — fans (FD; ID; PA); mills; ESP; coal handling plant; ash handling; cooling water pumps; lighting; HVAC; DCS and UPS. Compare each sub-component against design values and historical trends. A sub-component drawing significantly more power than design indicates equipment deterioration — worn fan blades; choked filters; failing bearings requiring maintenance attention.

Step 2 — Metering Verification: Boundary metering at the grid delivery point certified by RLDC; sealed; calibrated — measures net generation. Gross generation is metered at the unit generator terminal. The difference between the two is auxiliary consumption. Verify: both meters are on the same calibration and testing cycle; any meter replacement or repair recorded; CEA (Installation and Operation of Meters) Regulations 2006 (as amended up to 2022) — accuracy class; calibration; sealing; testing frequency.

Step 3 — Normative vs Actual: Excess APC above CERC norm = (Actual APC% − Normative APC%) ÷ 100 × Gross generation kWh. This excess represents additional units consumed internally that cannot be billed — a direct financial loss. Financial impact = Excess APC units × applicable variable charge per unit. Refer Appendix 1.

8.3.5 Specific Oil Consumption (SOC) Audit

Applicable Norm: 0.30 ml/kWh under CERC 2024-29 Regulations for thermal stations.

Formula: SOC = Total oil consumed in ml ÷ Gross generation in kWh.

Step 1 — Oil Log Verification: Maintain and verify the oil consumption log — unit-wise; date-wise; quantity of Heavy Fuel Oil (HFO) and Light Diesel Oil (LDO) consumed. Cross-verify against oil tank dip readings — opening level; closing level; receipts; consumption computed from tank level should match log entries. Cross-verify against oil receipts from supplier — delivery dockets; tank truck meter readings.

Step 2 — SOC Computation: SOC = Total oil consumed (ml) ÷ Gross generation (kWh). Compare against 0.30 ml/kWh normative. High SOC may arise from: poor coal quality requiring oil support for flame stability; poor flame stability in the boiler; equipment problems; or deliberate excessive oil firing with oil diversion. Each possibility requires different audit response.

Step 3 — Oil Price and Cost: Verify oil procurement price — competitive procurement; comparison with published petroleum pricing benchmarks. Excess oil consumption above normative SOC is expensive and cannot be recovered through FPA.

Red Flags: SOC dropping suddenly just before the CERC true-up assessment period with no corresponding operational change; oil tank dip records not maintained in tamper-proof format; oil received from single supplier without competitive process; tank calibration chart not updated after tank repair. Refer Appendix 1.

8.4 Environmental Compliance Audit

Applicable Standards: MoEFCC Notification S.O. 3305(E) dated 7 December 2015 and subsequent amendments, including G.S.R. 465(E) dated 11 July 2025. Applicable emission standards and compliance requirements vary according to unit vintage, location category and subsequent amendments. Refer Appendix 2 for the applicable standards matrix.

Step 1 — CEMS Audit: The Continuous Emission Monitoring System (CEMS) is the primary technical evidence of emission compliance. CEMS data is transmitted in real time to CPCB's Online Continuous Emission Monitoring System (OCEMS) portal. Manipulation of CEMS data is a recognised risk with documented instances in the power sector.

Verify CEMS is connected to CPCB OCEMS portal and transmitting data in real time — pull CPCB portal data and compare against plant-side CEMS log for the same periods. Verify CEMS calibration records — last calibration date; calibrating agency; calibration standards used. Identify data gaps — periods of zero data; periods of identical repeated readings; data uploaded in clearly visible batches rather than continuous stream. Batch-uploaded data indicates offline data entry rather than real-time transmission — a significant red flag. Cross-verify CEMS data against quarterly stack testing reports conducted by MoEFCC-approved laboratory — large divergence between stack test results and CEMS averages for the same period indicates CEMS data manipulation.

Step 2 — FGD Compliance Audit: Determine the plant's location category under the applicable MoEFCC amendments — Category A (within 10 km of NCR or million-plus cities), Category B (within 10 km of Critically Polluted Areas or Non-Attainment Cities), or Category C (others) — and identify the SO_2/FGD requirement and timeline currently applicable to the plant. Where SO_2 compliance/FGD installation is required, verify progress against the notified timeline and environmental compensation, if applicable. For FGD-installed plants, verify operational status, availability, limestone consumption, gypsum generation/disposal and SO_2 emissions. Verify separate accounting of FGD-related O&M costs in accordance with applicable CERC requirements.

Step 3 — Fly Ash Utilisation Audit: 100% fly ash utilisation is mandatory under MoEFCC rules. The obligation covers both fly ash and bottom ash.

Verify Fly ash utilisation report (CPCB portal) — accuracy; timely submission. Verify ash sale agreements — buyers (cement companies; brick manufacturers; road construction); quantities per agreement; actual quantities lifted; price; revenue accounted. Physical reconciliation: fly ash generated = coal consumed × ash content percentage × fly ash fraction. Compare against sum of fly ash utilised (sold; given free; used in construction) + ash remaining in ash pond. Significant gap — ash on paper is utilised but ash pond continues to grow is a major red flag indicating fictitious utilisation entries.

Ash pond stability — annual certificate from IIT or NIT as required by CPCB; third-party inspection records; ash pond dyke condition; freeboard compliance. FGD gypsum **—** verify quantity generated; sale, utilisation or disposal records; buyer/off-taker agreements; dispatch records; stock at site; and reconciliation of opening stock, generation, sale/utilisation/disposal and closing stock.

Step 4 — Water Compliance: Verify water withdrawal permission — validity, quantity permitted and actual withdrawal versus permitted quantity. Compare actual water consumption against applicable MoEFCC norms — 3.5 m^3/MWh for existing plants and 3.0 m^3/MWh for new plants installed after 1 January 2017; verify ZLD compliance for new plants, as applicable. Verify ETP operational status and effluent quality. State water charges — reconcile water drawn with permitted/billed quantity and verify payment to the competent State authority. Verify compliance with applicable cooling-water recycling/closed-cycle cooling requirements.

Step 5 — Environmental Clearance Conditions Compliance: EC and SPCB Consent Compliance: List every EC condition (often 50 to 100 for a thermal plant) and every CTO condition, and verify the status of each. Check that half-yearly EC compliance reports are filed with MoEFCC/SPCB on time and are accurate; that the CTO is valid, with renewal applied for before expiry; that quarterly stack monitoring is done by an approved laboratory and is within consented limits; and that any show-cause notice or SPCB inspection observation has been acted on within the stipulated period, including an assessment of bond forfeiture risk.

Red Flags: CEMS readings constant for long periods without natural variation, suggesting synthetic data; CEMS gaps coinciding with periods of high generation, masking peak emissions. Refer Appendix 2.

8.5 Tariff Petition Pre-Filing Audit

Step 1 — Capital Cost Verification: Verify capital cost as per books — reconcile with the fixed asset register; check that all assets included are related to the power generation activity. Capitalization timing — COD date for each unit; assets capitalized before COD vs after COD; any premature capitalization where assets were capitalized before the unit achieved commercial operation — this inflates capital cost and therefore depreciation and ROE claims. CERC-admitted capital cost from the original petition vs actual capital cost — if actual exceeds admitted, only the admitted portion is recoverable; compute the exposure. Additional capitalization after COD — capital works completed post-commissioning; CERC admission requirements; auditor certificate needed.

Step 2 — O&M Cost Verification: Actual O&M cost per MW — compare against CERC normative O&M per MW for the unit type under 2024-29 Regulations. Items typically disallowed by CERC are listed in Appendix A11.3. Verify each head of expenditure against that framework.

Step 3 — Interest and Finance Charges: Loan schedule — outstanding principal at year start; interest rate; repayment during year; outstanding at year end. CERC's normative debt is 70% of admitted capital cost, interest allowed at the weighted average rate of the actual loan portfolio (Appendix A1.5). Apply those norms to compute recoverable interest.

Step 4 — FPA Reconciliation: FPA claimed in the petition for the true-up period — reconcile with actual FPA billed and received month-by-month (see Section 8.2.7). Cross-verify coal consumption in FPA computation against station coal records. Quantify any computation error.

Step 5 — Generation Data — RLDC/SLDC Certification: Net generation data used in the petition must be from RLDC/SLDC-certified generation statements; not internal plant meter readings. Obtain RLDC/SLDC-certified annual generation statements. Reconcile with internal generation records — any unexplained difference. Reconcile with CEA National Power Portal submission — the same generation data submitted to CEA must match the petition data.

Red Flags: Capital cost includes items clearly not related to power generation such as residential colony construction; management guest house; items purchased for headquarters use; O&M cost significantly above normative without specific documented justification for each excess item; generation data in petition differs from CEA NPP submission for the same period.

8.6 Capital Works Audit

8.6.1 Scope of Capital Works in Thermal GENCO

Capital works in a thermal GENCO include new generating units (greenfield/brownfield expansion), R&M for life extension, FGD installation (mandatory environmental compliance), capital repairs, Balance of Plant, and township development. CERC capitalisation treatment for each category — what is fully admissible, partially admissible, and not recoverable through tariff is covered in Section 14.1.2 and Appendix A1.5. This section covers the GENCO-specific additions: CERC prudency, IBR compliance, COD timing, and capitalisation treatment in the tariff petition.

8.6.2 Audit Procedures

Step 1 — Procurement Process — CERC Prudency Dimension: Beyond the standard NIT; bid evaluation; and L1 procedures covered in Chapter 14, CERC examines whether procurement was competitive and whether the price was prudent. Single-tender procurement even if administratively justified — faces CERC scrutiny. Verify that for all major capital contracts, the GENCO can demonstrate: competitive process; price benchmarking; and technical justification if L1 was not selected.

Step 2 — Measurement Book Integrity: The Measurement Book (MB) is the foundation of contractor payment certification. MB manipulation — recording work as complete when it is not is one of the most common and most material frauds in capital works. Verify: all MB entries are in ink with no erasure; overwriting is not permitted; entries are sequential with no blank pages; MB is counter-signed by both the certifying engineer and the contractor's representative; bulk entries covering multiple months made on a single date, a strong indicator of retrospective fabrication; MB custody and access — controlled; surprise physical verification of work against MB entries.

Step 3 — Running Account Bills Certification: RA bills must be certified strictly against MB entries — no advance certification for work not yet measured. Verify: bill amount corresponds to MB-certified quantities × contract rates; escalation computation uses correct indices (CPI/WPI as specified in contract); advance payment recovery is being made from each RA bill at the agreed recovery rate; liquidated damages for delay are being deducted where applicable; retention money is withheld at contracted percentage.

Step 4 — Variation Orders: Any deviation from contracted scope must be formally approved as a Variation Order (VO) before the work is executed, not retrospectively. Verify: VO approval authority as per DFP; VO approved before work commenced; price justification for VO — compared to original contract rate for similar work; cumulative VO value as a percentage of contract value — if VOs exceed 15% of the original contract value, re-tendering may be required under the procurement policy; deliberate under-scoping at tender stage to keep within the approval limit with planned VOs, a strong indicator of procurement manipulation.

Step 5 — Capitalization Timing — CERC Implications: COD declaration must be based on: first synchronization to grid; successful completion of test runs at rated capacity; IBR certificate for boilers; CEA inspection certificate. Assets must not be capitalized before COD — any pre-COD capitalization overstates capital cost and accelerates tariff recovery incorrectly. Verify COD date supporting documents — RLDC/SLDC trial-operation certificate; SLDC synchronization record; test run reports; IBR certificate. Capital Spares (Initial) up to 4% of capital cost are admissible under CERC 2024-29 — verify correct classification of Capital Spares (Initial) vs revenue stores; items above the 4% limit are not recoverable through tariff.

Step 6 — IBR Compliance: Boilers Act 2025 and IBR 1950 (as amended) govern all pressure parts of the boiler. IBR approval is required for all pressure part materials; welding qualifications for pressure part welding; inspection by the State Boiler Inspectorate or a recognised Inspecting Authority; IBR registration and operating certificate before commissioning. Verify all IBR certificates for the boiler and pressure vessels; any repairs to pressure parts — IBR re-inspection required before return to service.

Red Flags: a single large contract split into smaller ones to stay below the DFP approval threshold; a contractor starting work before the contract is formally executed.

8.7 Gas-Based Power Plant — Specific Audit Considerations

Gas-based power plants have a fundamentally different fuel supply chain from coal-based plants. The following audit points supplement the standard GENCO audit framework for gas plants.

Fuel Supply Agreements: Gas Supply Agreement (GSA) with GAIL or other authorised gas supplier; contracted quantity; price formula typically linked to natural gas pricing; take-or-pay minimum off-take obligation; force majeure provisions. Gas Transmission Agreement with GAIL for pipeline transmission; PNGRB-approved tariff for gas transmission; delivery pressure specification. LNG import — if applicable; regasification terminal charges; Customs duty on LNG; IGST; Excise duty where applicable.

Gas Allocation: Government-allocated gas under APM (Administered Price Mechanism) is priced lower than market-priced gas. A plant may receive a mix of APM and market gas. Verify: correct allocation of gas between APM and market; price differential correctly applied; any change in gas allocation notified by MoPNG — applied from correct date.

Specific Audit Points: Gas metering at delivery point — custody transfer meter; calibration; sealing; PNGRB standards; take-or-pay obligation computation — minimum off-take commitment per GSA; if actual off-take is below minimum, take-or-pay payment is due — verify computation and payment; gas quality specification — GCV (in Kcal/scm; quantities in MMBTU); sulphur content; Wobbe Index — specification compliance and billing adjustment if quality falls outside specification.

CERC KPI norms for gas plants: For CERC KPI norms applicable to gas-based plants (SHR, PAF, APC), refer Appendix 1. Note that SHR norms for CCGT units differ significantly from coal plant norms.

8.8 Fraud Risk Indicators — Thermal GENCO

The fraud schemes mentioned in Appendix 10 are documented in CAG Audit Reports, CERC proceedings, and internal audit findings from power sector entities. For each scheme, the detection procedure is specifically designed to identify the fraud signature.

9. GENCO AUDIT — INTEGRATED COAL MINE OPERATIONS

9.0 Introduction

Many Central and State generating companies operate captive coal mines allotted to them under the Coal Mines (Special Provisions) Act 2015 for fuel security. This chapter provides the complete internal audit framework for captive coal mines operated by GENCOs.

As established in Section 7.2, where a GENCO operates a captive mine, the GENCO audit framework in Chapter 8 leads and the mine audit is the addendum. The mine brings its own distinct regulatory framework, which creates audit areas completely different from the power plant: the OSH Code 2020 (effective 21 November 2025, subsuming the Mines Act, 1952); the Coal Mines Regulations 2017, as continued under the transitional framework; the MMDR Act 1957; and the Coal Mines (Special Provisions) Act 2015. An internal auditor assigned to an integrated GENCO must be conversant with both frameworks.

This chapter covers only the mine-specific audit areas. Power plant audit is covered in Chapter 8. The coal-to-plant interface — particularly CERC mine input price petition and transfer pricing is covered in Section 7.2. The mining laws applicable to captive mines are detailed in Section 5.6.

The audit areas in this chapter are organised by risk significance — regulatory compliance and statutory payments first (because non-compliance attracts prosecution and penalties), followed by safety compliance, coal quantity and quality, MDO contract, environmental compliance, and mine closure etc.

9.1 Red Flag Dashboard — Captive Coal Mine

The following ten indicators provide a quick assessment of potential control problems at a captive coal mine. The internal auditor should evaluate all ten at the commencement of every mine audit cycle.

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
1	Production below MoC-approved mine plan	Below 80% of approved annual production target	Mine plan compliance risk; MoC review; GENCO may need to procure additional coal at higher cost
2	OB:Coal strip ratio above mine plan	More than 10% above planned ratio for two consecutive quarters	MDO over-payment; mine plan deviation; MoC scrutiny
3	Royalty payment delayed	Any month's royalty unpaid beyond due date	State Government penalty; interest; prosecution risk under MMDR Act
4	DMF contribution not deposited	Any month's contribution pending beyond 30 days	MMDR Act violation; prosecution of responsible officers
5	DGMS inspection findings unaddressed	Any critical safety observation unaddressed beyond 90 days	Mine closure order risk; prosecution of Mine Manager
6	GCV of mine coal below production target	More than 5% below targeted GCV consistently	Fuel cost impact at power plant; CERC transfer price implications

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
7	Weighbridge calibration lapsed	Legal Metrology Act calibration certificate beyond validity	Legal violation; dispatch records unreliable; fraud risk
8	Mine closure fund below required level	Escrow account balance below MoC-prescribed annual accumulation	MMDR Act non-compliance; MoC may suspend operations
9	EC conditions compliance report overdue	Half-yearly compliance report not submitted within due date	MoEFCC/SPCB non-compliance; EC cancellation risk
10	DGMS prosecution cases pending beyond 2 years	Any prosecution case unresolved beyond 2 years	Officer career risk; organisation reputational risk; governance failure

9.2 Mining Regulatory Compliance Audit

9.2.1 Coal Block Allotment Compliance

Applicable law: Coal Mines (Special Provisions) Act 2015; Coal Block Allotment Order issued by Ministry of Coal.

The allotment order is the foundational document for a captive coal mine. Every condition in the allotment order is legally binding and non-compliance can result in cancellation of the allotment, effectively shutting down the mine and the fuel security it provides.

Audit Procedures: Obtain the allotment order — read every condition carefully. Key conditions to verify:

End-use restriction: Coal from the captive mine must first meet the requirement of the allottee's linked end-use plant. Sale of surplus coal is permitted only within the limit now allowed by law (up to 50% of annual production), on payment of the prescribed additional amount. Verify: dispatches to the GENCO's own plant; any sale within the permitted limit and with the additional amount paid; no diversion beyond it or to related parties at undervalued prices.

Production targets: Allotment orders specify progressive production ramp-up targets — typically Year 1 through Year 5 with increasing quantities. Verify achievement vs target year-wise; where shortfall exists — documented force majeure or Ministry of Coal approved extension; monitoring committee notified.

Revenue share for auctioned blocks: For blocks allocated through auction, revenue share percentage was bid. Verify correct revenue share computation — percentage of revenue from coal value at notified price × coal dispatched; monthly payment to State Government; any arrears; interest on delayed payment.

Monitoring committee compliance: Ministry of Coal constitutes a monitoring committee for each captive block. Committee meetings are held quarterly. Verify: GENCO's attendance at all monitoring committee meetings; compliance reports submitted before each meeting; any adverse observations from monitoring committee — action taken; compliance reported.

Transfer restrictions: The captive coal block cannot be transferred to any other entity without Ministry of Coal approval. Verify: no sub-leasing of any portion of the mine; MDO contract does

not amount to transfer of mining rights — MDO is a service contractor; the GENCO remains the allottee and operator in regulatory terms.

Red Flags: Coal sold beyond the permitted limit or without the additional payment; monitoring committee meetings not attended; production significantly below ramp-up targets for consecutive years without Ministry of Coal extension; MDO contract giving MDO rights that effectively amount to mining rights transfer and inconsistency of terms between allotment order and MDO agreement etc.

9.2.2 Mining Lease Compliance

Applicable law: Mines and Minerals (Development and Regulation) Act 1957; Mineral Concession Rules 1960; State Mining Rules of the applicable state.

Audit Procedures: Verify mining lease deed — validity period; area in hectares; specific conditions of the lease grant; lessee's obligations. Lease renewal — where lease is approaching expiry, renewal application must be filed before expiry; check if filed timely; conditions of renewal; any additional conditions imposed.

Mining operations within leased area — verify through filed returns and site records that mining is being conducted only within the leased boundary. Any mining outside the leased area even by a few metres constitutes an illegal mining offence under MMDR Act.

Red Flags: Mining lease expiring within 6 months without renewal application filed; quantities inconsistent with weighbridge records and returns filed; mining activity evident beyond the surveyed lease boundary etc.

9.2.3 Ministry of Coal Mine Plan Compliance

Applicable law: Coal Mines (Special Provisions) Act 2015; MMDR Act 1957; Ministry of Coal Guidelines.

Every captive coal mine must operate under an approved mine plan that specifies annual production targets; overburden removal quantities; strip ratio; mining methodology; environmental management; and progressive mine closure activities. Deviation from the approved mine plan requires the Ministry of Coal approval before implementation.

Audit Procedures: Obtain the current approved mine plan — verify it is valid and current; next revision due date. Compare actual production month-wise against approved annual production — any month significantly below plan without force majeure explanation. OB removal month-wise against approved OB quantities — the strip ratio (OB removed in BCM ÷ coal produced in tonnes) must be within the range approved in the mine plan.

Progressive mine closure: verify that mined-out areas are being progressively rehabilitated as required by the mine closure plan embedded in the mine plan — backfilling of voids, re-contouring, topsoil replacement and revegetation. Verify quarterly progress against the plan.

Mine plan revision — where actual geological conditions differ significantly from what the mine plan assumed (GCV lower than expected; seam thickness different; faulting encountered), a revised mine plan must be submitted to Ministry of Coal. Verify: any material change in actual conditions documented; revised plan submitted if required; Ministry approval obtained before continuing on revised basis.

Financial Impact: Where actual production falls below approved mine plan then the GENCO may need to procure additional coal from CIL at market rates rather than at the lower captive mine transfer price. Financial impact = (Mine plan production − Actual production) in tonnes × (CIL FSA coal cost − Mine transfer price) per tonne.

9.3 Statutory Payments Audit

All statutory payments from mine operations are time-sensitive. Delay attracts penalty and interest. Non-payment beyond specified periods constitutes an offence under the applicable law and even leads to cancellation of allotment of mine. This is therefore a high-priority audit area with low tolerance for laxity.

9.3.1 Royalty

Applicable law: MMDR Act, 1957 — Section 9 and Second Schedule; royalty rates for coal notified by the Ministry of Coal.

Computation: Royalty = Applicable value/price basis of coal × applicable ad valorem royalty rate (currently 14%). For captive coal mines, determine the applicable price basis in accordance with the prevailing Ministry of Coal notification, including the prescribed ROM coal price/GCV basis. Confirm the rate and price basis from the latest notification.

Audit Procedures: Monthly royalty computation — reconcile coal quantity/dispatch with mine records and statutory returns and verify the applicable price basis and royalty rate.

Timely payment — verify payment against the applicable statutory due date; compute interest/other consequences for delayed payment, where applicable.

Filing returns accuracy — quantities and values reported in statutory returns should reconcile with mine, weighbridge and accounting records.

Royalty rate revision — monitor Ministry of Coal notifications and ensure that revised rates or computation methodology are applied from the effective date.

Financial Impact: Delayed royalty interest = Outstanding royalty × applicable interest rate × period of delay.

9.3.2 District Mineral Foundation (DMF)

Applicable law: MMDR Act 1957 Section 9B; Pradhan Mantri Khanij Kshetra Kalyan Yojana (PMKKKY) 2015; applicable State DMF Rules.

Applicable Rates:

- ✓ Mines allotted on or after 12 January 2015 — 10% of royalty
- ✓ Mines allotted before 12 January 2015 — 30% of royalty

Audit Procedures: Determine which rate applies — verify allotment order date against 12 January 2015 cut-off; apply correct rate. Monthly DMF computation — royalty amount for the month × applicable rate (30% or 10%). Payment to DMF Trust established by the District Collector of the mining district; verify payment made to correct DMF Trust account; payment receipt obtained; any arrears.

PMKKKY utilisation: DMF funds are utilised by the DMF Trust under the District Collector's oversight. The GENCO should keep records of its contributions and of its participation in DMF

Trust meetings, and verify that welfare activities in the mining-affected area are being supported as required.

Financial Impact: DMF shortfall = Required DMF amount − Amount actually deposited. Any shortfall attracts interest under the MMDR Act and State DMF Rules.

9.3.3 National Mineral Exploration Trust (NMET)

Applicable law: MMDR Act 1957 Section 9C; NMET Rules 2015.

Rate: 3% of royalty amount payable to NMET established by Ministry of Mines for funding regional and detailed mineral exploration.

Audit Procedures: Monthly NMET computation — royalty amount × 3%. Payment to NMET — transferred to National Mineral Exploration Trust account maintained by Ministry of Mines; verify payment date; receipt obtained; reconciliation of total NMET payments against total royalty payments.

9.3.4 Surface Rent

Surface rent is payable to the State Government or to landowners for the surface area occupied by mine operations including open cast mining area; OB dumps; infrastructure; haul roads; and plant area within the mine lease.

Rate and computation vary by state — verify the applicable State Mining Rules; rate per hectare; area subject to surface rent; annual computation; timely payment; receipt obtained.

9.3.5 Reserve Price and Other Allotment/Auction Payments

Applicable law: Coal Mines (Special Provisions) Act 2015; Coal Mines (Special Provisions) Rules 2014, as amended; applicable auction/allotment methodology and Allotment/Vesting Order issued by the Ministry of Coal.

The successful allottee/bidder is required to pay the reserve price, revenue share, additional premium and other amounts, as applicable under the relevant auction/allotment methodology and the terms of the Allotment/Vesting Order. Where the applicable methodology prescribes a per-tonne reserve price payable to the coal-bearing State Government, such payment is in addition to royalty and other statutory levies.

Audit procedures: Identify the applicable auction/allotment regime and verify the reserve price, revenue share, additional premium and other payments specified in the Allotment/Vesting Order; verify applicable escalation/adjustment; reconcile production/dispatch quantities and notified coal price, where relevant, with payment computations; verify payment to the prescribed Government/authority within the stipulated timelines; and quantify interest, penalty or other exposure arising from delayed or short payment.

9.3.6 Statutory Payments Consolidated Register

The internal auditor should verify that the mine maintains a single consolidated statutory payments register covering all statutory payment heads applicable to the mine — Royalty; DMF; NMET; Surface Rent; Reserve Price; and Revenue Share (for auctioned blocks) and state levies such as Mineral Bearing Land Cess. The register should show for each payment: applicable period; due date; amount computed; amount paid; payment date; receipt reference; any variance. This register should be verified monthly by the mine's finance function and quarterly by internal audit.

9.4 DGMS Safety Compliance Audit

Safety compliance in coal mines is the most critical governance obligation for a mine operator. The OSH Code 2020 (which subsumed the Mines Act, 1952 from 21 November 2025) and the Coal Mines Regulations 2017, as continued under the transitional framework, impose extensive and detailed safety requirements. Non-compliance has two dimensions: the regulatory risk of prosecution and mine closure; and the human risk of accidents that result in loss of life and injury to mine workers. Internal audit has a responsibility in both dimensions.

Step 1 — DGMS Inspection Report Compliance: DGMS inspectors visit mines periodically, typically once or twice annually for open cast mines and more frequently for underground mines. Each inspection results in an Inspection Report with observations categorised as critical; serious; and general.

Obtain the latest DGMS Inspection Report — date; inspector's name; all observations listed. For each observation: verify compliance within the stipulated period; document evidence of compliance — photographs; engineer's certification; equipment purchase records. Any critical DGMS observation unaddressed beyond 90 days constitutes a major audit finding — escalate immediately to Audit Committee. Track all pending observations in a DGMS Compliance Register — cross-reference with Appendix A11.4.

Step 2 — Statutory Appointments and Qualifications: The OSH Code 2020 and the Coal Mines Regulations 2017 (and, for periods before 21 November 2025, the Mines Act 1952) prescribe mandatory appointments for every mine. Verify:

Mine Manager — must hold a valid Manager's Certificate of Competency issued by DGMS; verify certificate number; validity; scope (opencast/underground); no gap in holding of the mandatory position. If the mine has been operating without a qualified Mine Manager — even for a day — it is an offence under the OSH Code 2020 (and, for earlier periods, the Mines Act, 1952).

Overman and Sirdar — for underground mines; required qualifications under Coal Mines Regulations 2017; verification of certificates.

Safety Officer — mines above a specified output must have a dedicated Safety Officer; qualifications prescribed; DGMS approval; verify appointment and qualification.

Ventilation Officer — for underground mines; separate appointment required; qualifications; DGMS approval.

Ratio of safety personnel to workers — the Coal Mines Regulations 2017 prescribe minimum ratios; verify actual workforce vs number of qualified safety personnel.

Step 3 — Safety Infrastructure Verification: VHF Communication System — mandatory for underground mines; all underground workings must be within VHF communication range; daily communication check records. In-mine telephone system — tested and functioning.

Self-Contained Self-Rescuer (SCSR) devices — one per person permitted underground; type-approved by DGMS; inspection records; expiry date of breathing media. SCSR is a critical life-safety device for underground coal mines where spontaneous ignition or gas outburst can make the atmosphere rapidly unbreathable.

Methane monitoring **—** for underground coal mines, verify availability, calibration and use of prescribed gas-detection and monitoring equipment; records of methane concentrations; and

compliance with the action levels prescribed under the Coal Mines Regulations, 2017 for de-energising electrical equipment, suspending operations and withdrawing persons, as applicable. Verify that exceedances are recorded, investigated and reported/escalated in accordance with the applicable requirements.

Refuge Chambers — for underground mines above a specified depth; equipped; air supply; food; first aid; communication.

First Aid stations — equipped; adequate for workforce; trained first aiders ratio; ambulance availability.

Emergency Response Plan (ERP) — documented; tested with mock drills; mock drill records for last 12 months; coordination with local district administration; district disaster management plan linkage.

Step 4 — Accident and Near-Miss Reporting: Accident Register — all accidents recorded immediately; DGMS notification timelines: loss of life, serious bodily injury and specified dangerous occurrences to be reported forthwith to the Regional Inspector, followed by prescribed notice within 24 hours in accordance with Regulation 8 of the Coal Mines Regulations, 2017.

Near-miss Register — recording of near-miss events; root cause analysis; corrective action. Near-miss reporting culture is an indicator of safety management maturity — absence of near-miss records in an active mine is itself a red flag (not that there are no near-misses, rather that they are not being reported).

Prosecution Register — any DGMS prosecution cases filed against mine officials or the organisation; court dates; outcomes; provisions made; impact on personnel. DGMS prosecutions are personal criminal liability on the responsible officers like the Mine Manager; the Safety Officer; the mine owner. Internal audit should track all prosecution cases and escalate to senior management and Board.

Step 5 — Explosives Management: For open cast mines using explosives for blasting — PESO (Petroleum and Explosives Safety Organisation) licence for explosives storage — validity; conditions; maximum quantity authorised.

Licensed magazine — construction as per PESO specifications; stock register; daily stock reconciliation; authorised access only; magazine keeper appointed and qualified.

Explosives consumption vs blasting records — each blasting event should be authorised by a Shot Firer holding DGMS competency certificate; quantity of explosives used per blast recorded; actual consumption over the period should match blasting records. Any systematic excess of explosives drawn from magazine vs blasting records is a serious red flag — possible diversion.

Blasting records — blast time; area blasted; OB or coal face; shot firer identity; flyrock incidents; ground vibration records where applicable (residential areas near mine boundary).

Red Flags: Mine Manager certificate expired or not renewed; SCSR expiry date passed with no replacement ordered; DGMS critical observations pending beyond 90 days; near-miss register showing zero entries over months in active mining — culture of non-reporting; explosives drawn from magazine consistently exceed quantities in blasting records — diversion risk; mine rescue team not constituted or not trained in last 12 months.

9.5 Coal Quantity and Quality Audit

9.5.1 Production and Dispatch Records

The coal production and dispatch records are the basis for: Statutory Returns submissions; statutory payment computations; MDO payment claims; transfer pricing to power plant; and GCV-based financial impact calculations at the plant. These records must be accurate, tamper-resistant, and independently verifiable.

Weighbridge Compliance: Legal Metrology Act 2009 — weighbridge at mine dispatch point must be calibrated periodically by a certified agency; calibration certificate must be current; weighbridge sealed. Verify: last calibration date and certificate; calibrating agency's certification; sealing record; CCTV at weighbridge — same procedures as Section 8.2.5 apply. Software audit trail — access logs; manual overrides recorded; no post-hoc modification of weighment records.

Dispatch Records Verification: Truck-wise or conveyor-wise coal dispatch — challan number; truck registration; net weight; destination (must be own power plant); date and time. Verify: total dispatch per month reconciles with weighbridge records; dispatch destination is the GENCO's own plant only — no diversion; GPS tracking for road transport trucks from mine to plant.

Production vs Dispatch vs Stock Reconciliation: Opening stock + Production = Dispatch + Closing stock + normal losses. Verify: coal face production records — shift-wise; cross-check with mining equipment productivity records (shovel capacity; number of shifts; operational hours); coal dispatched from weighbridge; coal stocked at mine stockyard — physical measurement.

Any systematic gap between production records and actual dispatch plus stock indicates either: over-reporting of production; under-recording of dispatch; or both — possible fraud in MDO payment claims (MDO paid per tonne produced — inflating production records inflates MDO payment).

Railway Dispatch (Where Applicable): For mines with railway connectivity — rake-wise dispatch; RR (Railway Receipt) numbers; rake loading weights; destination plant. Reconcile with railway freight bills; transit shortage claims if applicable.

9.5.2 Overburden (OB) Removal Audit

OB removal is the single most significant payment under most MDO contracts — typically paid per Cubic Metre (BCM or LCM) of OB removed. It is also the primary parameter monitored by MoC for mine plan compliance. Over-reporting of OB removal results in excess MDO payment; under-reporting results in Mine plan non-compliance.

Strip Ratio Computation: Strip ratio = OB removed (in Cubic Metres) ÷ Coal produced (in tonnes). The approved mine plan specifies the expected strip ratio for each year and each mining area. Actual strip ratio should be within a reasonable range of the approved strip ratio. Significant excess like above 10% may indicate: mining in areas with higher stripping ratio than planned (geological deviation requiring approved mine plan revision); or OB over-reporting for MDO payment inflation.

OB Removal Measurement: OB removal is measured in two ways — by survey measurement of the volume removed from the mining face; and by measurement of the volume deposited in the OB dump. Both should agree once the dump volume (loose cubic metres) is converted to bank cubic metres using the documented swell factor. Discrepancy beyond that is a red flag.

Conduct independent OB measurement using GPS-based survey or drone photogrammetry. Compare with MDO's claimed quantities. GPS/drone survey provides tamper-resistant independent evidence of actual volume moved. Maintain survey records with timestamps and surveyor credentials.

OB dump stability — large OB dumps must have slope stability analysis conducted by qualified geotechnical engineer; slope angle within safe limits; surface drainage to prevent erosion; toe protection. Failure of an OB dump has caused fatalities in Indian mines. Verify annual stability certificate from competent engineer.

Red Flag: Strip ratio in a specific mining area persistently above the approved ratio without geological explanation — MDO over-billing risk; OB face survey and OB dump survey consistently showing material difference — measurement manipulation.

9.5.3 Coal Quality Audit at Mine

Third-Party Sampling at Mine Dispatch Point:

Coal samples must be drawn at the mine dispatch point (weighbridge) by CIMFR or another third-party agency appointed by the GENCO. Sampling frequency; sample size; sample preparation; chain of custody — all must comply with BIS/ASTM standard. Verify: sampling agency credentials — CIMFR or another third-party agency appointed by the GENCO; independence; sampling protocol compliance records.

GCV Analysis: Samples sent to accredited laboratory like NABL-accredited laboratory for GCV analysis by bomb calorimeter; results compared against approved mine plan target GCV for that seam and area; results compared against CERC-determined transfer price GCV band; any systematic shortfall below target GCV — investigate: geological variation; coal blending with poor quality coal; sampling manipulation.

GCV at Dispatch vs GCV at Receipt at Power Plant: Cross-verify GCV reported at mine dispatch against GCV at destination sampling at the power plant for the same consignment. Systematic downward difference at destination exceeding normative transit loss requires investigation. Reference: Section 8.2.2 covers the power plant end of this verification.

Online Coal Analyser: Where the mine has installed an online coal analyser at the dispatch point — verify calibration records; comparison against laboratory analysis; data integrity; who has access to analyser settings.

9.6 MDO Contract Audit

The Mine Developer and Operator model is common for captive coal mines where the GENCO does not have in-house mining expertise. The MDO, selected through competitive tendering performs all or most mining operations for a contractual payment. The GENCO retains ownership; regulatory responsibility; and oversight. MDO contract audit is one of the highest-value audit areas in mine operations because the MDO contract is typically the single largest expenditure line in mine operations.

9.6.1 MDO Procurement and Contract

Verify MDO was selected through competitive bidding — NIT adequately publicised; eligibility criteria appropriate; technical bid evaluation — mine developer experience; financial strength; equipment fleet; bid price evaluation; L1 determination; Board approval for contract award.

Contract terms — payment basis (per tonne of coal produced; per BCM of OB removed; or combination); rate escalation formula (CPI/WPI linkage; components; weights); performance targets — coal production; OB removal; quality; safety; contract period; extension provisions; termination clauses; performance guarantee amount and form; advance payment provisions; recovery mechanism.

9.6.2 MDO Performance vs Contract

Monthly performance monitoring — actual coal production by the MDO vs contractual target; any shortfall — shortfall penalty computation; incentive payment if production exceeds target — computation accuracy. OB removal by MDO vs target — strip ratio compliance; excess OB claim vs mine plan.

Verify: performance claims submitted by MDO each month; GENCO's independent verification of MDO claims before payment — independent measurement; GENCO's measurement engineer signing off on quantities.

A critical internal control: MDO payment must not be based solely on MDO's own production and OB claims. The GENCO must independently verify quantities through its own measurement engineers or through a third-party independent surveyor appointed by the GENCO. Where independent verification is absent and MDO payment rests entirely on self-reported quantities, this is a fundamental control failure.

9.6.3 MDO Payment Computation

Per-unit rate × independently verified quantity = base payment. Rate escalation computation — correct indices applied; correct base period; correct weightages for each component (fuel; labour; material etc.); computation verified against published CPI/WPI data.

Advance payment — Board approval obtained; utilisation certificate submitted for prior advance before fresh advance; recovery from running bills at contracted percentage — no advance outstanding beyond utilisation certificate period.

Final bill — all advances recovered; performance guarantee released only after defect liability period; any pending claims — documented; resolved through contract dispute resolution mechanism.

Financial Impact Formula: MDO over-payment due to quantity over-reporting = (MDO-claimed quantity − Independently verified quantity) × MDO contract rate per unit = Rs. excess payment.

MDO rate escalation over-computation = (Incorrect rate − Correct rate) × Quantity = Rs. excess payment.

9.6.4 MDO Statutory Compliance

The MDO is an independent contractor but the GENCO as principal employer has statutory liability under several labour laws for the welfare and legal protection of MDO workers.

EPF and ESI: MDO must file monthly ECR (Electronic Challan cum Return) for PF contribution; ESI contribution for all MDO workers at the mine site. Verify: ECR copies from MDO for each month; EPFO UAN (Universal Account Number) allocation for all MDO workers; any EPFO/ESIC inspection notices.

Minimum Wages: MDO must pay minimum wages as notified for the mining industry under the Code on Wages 2019 and the applicable state notification (for periods before 21 November 2025, the

Minimum Wages Act 1948). Verify: applicable minimum wage rate; MDO payroll sample — wage rates paid vs applicable minimum wage; any arrear wages.

OSH Code 2020 — Contract Labour (earlier Contract Labour Act 1970): GENCO as principal employer must be registered under the OSH Code 2020 (earlier, the CLRA 1970); MDO as contractor must hold a valid licence; MDO must provide welfare facilities to mine workers — canteen; rest shelters; first aid. Verify: GENCO's principal employer registration; MDO contractor licence; welfare facility compliance.

BOCW Cess: Building and Other Construction Workers (BOCW) Act 1996 — BOCW cess at 1% of construction cost is applicable for mine development construction activities. Verify cess computation; payment; BOCW worker registration; welfare fund contributions.

POSH Compliance: Internal Complaints Committee (ICC) must be constituted at the mine for handling sexual harassment complaints. Verify ICC constitution; external member inclusion; annual report to District Officer.

9.6.5 MDO Equipment and HEMM

HEMM (Heavy Earth Moving Machinery) — shovels; dumpers; dozers; drills may belong to the GENCO or to the MDO. This distinction has significant financial and audit implications.

Where HEMM belongs to GENCO but operated by MDO — verify asset tracking; insurance in GENCO's name; maintenance logs; fuel consumption vs productivity benchmarks; any damage by MDO — recovery per contract terms.

Where HEMM belongs to MDO — verify equipment fleet size matches contractual commitment; equipment availability vs contractual availability guarantee; any equipment substitution — same or better specification; equipment productivity records.

Red Flags: GENCO's HEMM equipment transferred to MDO's books — asset diversion; MDO using fewer equipment than contracted — insufficient fleet; fuel consumption by HEMM inconsistent with productivity — fuel diversion or productivity inflation.

9.7 Mine Environmental Compliance Audit

Applicable laws: Environment (Protection) Act 1986; Air (Prevention and Control of Pollution) Act 1981; Water (Prevention and Control of Pollution) Act 1974; Van (Sanrakshan Evam Samvardhan) Adhiniyam 1980; EC conditions for the specific mine. Refer Sections 5.6 and 5.7 for the applicable legal matrix.

EC Conditions Compliance: Obtain the Environmental Clearance (EC) for the mine — list all conditions; categorise as: environmental monitoring conditions; pollution control conditions; forest and compensatory afforestation conditions; R&R conditions; production limit conditions. Half-yearly compliance report filed with MoEFCC/SPCB within due date; accuracy of compliance status in each report; any conditions reported as compliant but actually not complied with.

SPCB Consent to Operate — validity; renewal application filed before expiry; consent conditions compliance; any SPCB notices.

Mine Water Management: Underground mines and open cast mines both generate water inflows that require treatment before discharge. Mine water quality — pH; suspended solids; dissolved metals; must meet SPCB consent conditions for discharge. Mine water treatment system — operational; treatment capacity vs actual inflows; effluent quality testing records; SPCB consent for

discharge. Acid Mine Drainage (AMD) where the coal seam contains pyrite, oxidation can produce acidic mine drainage; AMD treatment; monitoring; discharge quality.

Dust Suppression: Open cast mining generates significant fugitive dust from: blasting; OB loading and dumping; haul road traffic; coal stockyard. Dust suppression measures — water sprinklers on haul roads; misting systems at loading points; dust monitors at mine boundary; SPCB ambient air quality monitoring; complaints from surrounding communities; SPCB notices.

OB Dump Management: Slopes must be within safe angle; progressive revegetation of stabilised OB dumps; surface water drainage channels to prevent erosion and silt runoff into streams; topsoil stockpiling and reuse; invasive species management on revegetated areas.

Forest Clearance Compliance: Where the mine lease involves forest land, Forest Clearance under the **Van (Sanrakshan Evam Samvardhan) Adhiniyam, 1980** is required, generally through Stage I (in-principle approval) and Stage II (final approval after compliance with stipulated conditions). FC conditions may include Compensatory Afforestation (CA), payment of Net Present Value (NPV), wildlife conservation/management measures, where applicable, and other project-specific conditions.

Verify: FC approval and conditions; CA compliance — land identification, plantation and survival status; NPV and other prescribed payments; implementation of wildlife conservation/management measures, where applicable; and compliance with other stipulated conditions. Verify that diversion/use of forest land has commenced only after obtaining the approvals and complying with the conditions required under the applicable forest-conservation framework.

9.8 Mine Closure and Rehabilitation Audit

Applicable law: MMDR Act 1957; Mine Closure Guidelines; State Mining Rules.

Mine closure planning is mandatory from the commencement of mining. The approved Mine Closure Plan defines what the mine must look like at the end of its productive life and how the land will be rehabilitated; what structures will be demolished; how the water table will be managed; and how the community will be supported through the transition.

Approved Mine Closure Plan: Verify the plan is approved by Ministry of Coal; current — mine closure plans require periodic updates as actual mining progresses; realistic — closure provisions match the actual extent and depth of mining. Any material deviation from the approved plan — for example, mining beyond the originally planned depth or area requires a revised closure plan.

Financial Provisioning — Escrow Account: Mine operators are required to provide financial assurance for implementation of the approved Mine Closure Plan through annual deposits into an escrow account. The closure cost is determined on the prescribed cost-per-hectare basis and adjusted/indexed as applicable under the Ministry of Coal guidelines, including WPI-based escalation. The annual deposit shall be made in accordance with the approved Mine Closure Plan.

Verify: escrow account exists with the **Coal Controller's Organisation as beneficiary**; annual deposit agrees with the approved Mine Closure Plan; deposits are made within the prescribed timelines; and cumulative deposits/released amounts reconcile with escrow records and closure obligations.

Escrow withdrawals/releases: Verify that amounts released from the escrow account are supported by implementation of eligible progressive/final mine-closure activities and have been

approved/released by the **Coal Controller** in accordance with the applicable Mine Closure Guidelines and escrow agreement. Verify expenditure and physical completion of the corresponding closure activities.

Progressive Mine Closure: Progressive mine closure — rehabilitation of mined-out areas while the mine is still operating is both a regulatory requirement and good practice. As each section of the mine is exhausted, that section should be backfilled (where feasible); re-contoured; topsoil applied; and revegetated. Verify quarterly progress of progressive closure against the mine closure plan milestones.

R&R (Resettlement and Rehabilitation): Project Affected People (PAP) entitlements under RFCTLARR Act 2013 and the mine-specific R&R plan include: housing; land for land (where applicable); employment preference; annuity; subsistence allowance. Verify: PAP register — all affected families identified; entitlement register — what each PAP is entitled to; actual delivery register — what each PAP has received; grievance register — PAP complaints and resolution; R&R colony — quality of housing; basic amenities — water; electricity; roads; schools. Unresolved R&R grievances can lead to local opposition to mining operations; legal proceedings; and reputational damage.

9.9 Fraud Risk Indicators — Captive Coal Mine

The following fraud schemes are documented from CAG audit reports; DGMS findings; and internal audit experience in captive mine operations. Detection procedures are specifically designed for each scheme.

Fraud Scheme	How It Works	Detection Procedure
Coal production over-reporting	Production records inflated to: (a) inflate MDO payment (MDO paid per tonne produced); (b) inflate coal transfer quantity to power plant at transfer price	GPS/drone volumetric survey of coal faces and stockyard; compare with weighbridge dispatch + actual stock; coal face progress photos with timestamps; HEMM productivity cross-check
OB removal over-reporting	MDO claims higher OB BCM than actually moved — paid per BCM; OB dump does not grow proportionately	GPS/drone survey of OB dump volume; compare with face survey; strip ratio analysis vs Approved plan; independent GENCO measurement engineer sign-off
Royalty evasion — dispatch under-reporting	Coal dispatched from mine without weighbridge entry or with reduced weight — royalty computed on lower quantity	Reconcile Coal Dispatch Annual Return with weighbridge records; cross-check coal receipts at power plant against mine dispatch; CCTV review of coal loading area at mine
GCV manipulation at mine dispatch	Sampling agency and MDO collude — better quality coal sampled and sent to laboratory; actual coal dispatched is lower quality; GENCO receives inferior coal but pays for better	GENCO-appointed independent surprise re-sampling; compare mine GCV with destination plant GCV; commission CIMFR verification sampling
MDO payment rate	Incorrect CPI/WPI indices applied;	Independently verify rate escalation

Fraud Scheme	How It Works	Detection Procedure
escalation manipulation	incorrect base period; incorrect component weights — MDO rate inflated in each escalation	computation using published CPI from the Labour Bureau (Ministry of Labour and Employment) and WPI from the Office of the Economic Adviser (DPIIT); verify against contract formula; recompute and compare
Explosives diversion	Explosives drawn from magazine for blasting — portion diverted for sale in open market	Monthly reconciliation of PESO-licensed quantity vs quantity received from explosives supplier vs blasting records quantity; any gap = diverted quantity; CCTV at magazine; blaster identity verification
HEMM fuel diversion	Diesel drawn for HEMM operation diverted — fuel consumption records inflated	Cross-verify diesel consumption with HEMM working hours and productivity; installed flow meters on fuel dispensing points; surprise fuel tank dip measurement; GPS-based HEMM movement records vs fuel claimed
Ghost workers in MDO payroll	Fictitious workers on MDO payroll — wages claimed; ESI/EPF contributions diverted	Biometric attendance at mine gate — headcount vs payroll; surprise headcount at face; EPFO UAN verification; compare ECR headcount with actual workers

10. GENCO AUDIT — RENEWABLE ENERGY

10.0 Introduction

Non-fossil sources now account for above 45% of India's installed generation capacity. Solar and wind together exceed 150 GW; pumped storage and BESS are growing rapidly; and green hydrogen has moved from policy to early commercial deployment. This chapter provides the internal audit framework for RE GENCOs covering solar, wind, hydro, pumped storage, BESS, green hydrogen, and nuclear power.

Unlike thermal plants, RE plants have no fuel cost and no Station Heat Rate to audit. The primary audit parameters are generation performance (CUF; PR; turbine availability; design energy achievement), REC compliance, project finance covenants, and environmental obligations. The financial risk concentrates in generation under-performance against PPA guarantees, REC revenue leakage, BESS degradation, and project finance covenant breach. Where a thermal GENCO also holds RE assets, apply Chapter 8 procedures to thermal assets and this chapter's procedures to RE assets. For hybrid RE plus storage configurations, refer Section 7.9.

10.1 Red Flag Dashboard — RE GENCO

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
1	Solar CUF below PPA guarantee	More than 2% below guaranteed CUF for two consecutive months	PPA penalty exposure; OEM panel/inverter warranty claim triggered
2	Wind turbine availability below OEM guarantee	Below 95% availability for two or more consecutive months	OEM warranty claim available but not filed; revenue loss
3	Solar Performance Ratio below benchmark	PR below 75% for any month	Panel soiling; inverter failure; shading — investigation required
4	BESS Round Trip Efficiency below guarantee	RTE below the OEM-guaranteed value (typically 85%)	OEM warranty trigger; degradation beyond warranted rate
5	REC not applied for two consecutive months	Two months without REC application to NLDC	Revenue loss; 180-day application deadline at risk
6	ISTS waiver eligibility not tracked	No register monitoring ISTS waiver status and expiry	Financial exposure if waiver lapses without replacement
7	DSRA below required level	DSRA balance below the level required by the loan agreement	Lender covenant breach; potential event of default
8	Independent Engineer report findings unaddressed	Any critical IE observation unaddressed beyond 90 days	Lender concern; safety risk; drawdown at risk
9	Forest Clearance conditions not monitored	No compliance tracking register for FC conditions	Legal risk; EC cancellation; project shutdown

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
10	Deemed generation claims not raised	Curtailment instructions in the register with no claim raised within the PPA period	Revenue loss; time-barred claims

10.2 Solar Power Audit

10.2.1 Scope and Coverage — Solar Power Audit

Solar power audit covers both the foundational parameters — panel condition, energy meters, battery systems, output voltage and amperage — and the expanded framework reflecting the significant growth of solar capacity since 2021. This section covers CUF audit against PPA guarantee, Performance Ratio computation and benchmarking, inverter availability audit; OEM warranty claim management; SCADA data cross-verification; panel degradation tracking; and REC audit. All of these are material audit areas.

10.2.2 Performance Parameters and Applicable Norms

Parameter	Formula	Benchmark (Indicative)	Primary Reference
Capacity Utilisation Factor (CUF)	Actual generation (kWh) ÷ (Installed capacity kW × 8,760 hrs) × 100	19–22% crystalline Si; 15–18% thin film; P90 from resource assessment report is the binding reference	PPA guaranteed CUF is primary obligation; not generic benchmark
Performance Ratio (PR)	Actual AC output (kWh) ÷ [Installed DC capacity (kWp) × Plane-of-array irradiation (kWh/m²) ÷ 1 kW/m²]	PR > 80% satisfactory; PR < 75% — investigate	Best efficiency indicator; factors out weather variation

10.2.3 Audit Procedures — Solar Plant

Step 1 — SCADA Data Cross-Verification: Extract actual generation data from the plant's SCADA (Supervisory Control and Data Acquisition) for the audit period. Compare with: generation data submitted to SLDC/RLDC for scheduling; generation data used for PPA billing to the DISCOM; generation data submitted for REC application to NLDC. All three should be identical — any difference requires explanation.

DC power at panel level (from string monitoring system) vs AC energy injected at the grid connection point — the difference represents system losses including inverter conversion losses; transformer losses; cabling losses. Significant unexplained losses indicate equipment problems.

String-level monitoring — identify strings performing significantly below average. Each string is a series of panels; an underperforming string indicates partial shading; faulty panels; cable connection failure; or inverter channel fault. Correlate underperforming strings with physical inspection findings.

Step 2 — CUF Audit: Compute monthly CUF — actual generation ÷ (installed capacity × hours in month). Compare against PPA-guaranteed CUF. Where actual CUF is below PPA guarantee for consecutive months, investigate root cause systematically:

Inverter availability: inverter downtime records per inverter unit — duration; reason; whether OEM responded within contract response time. Inverter availability below OEM guarantee triggers warranty claim.

Shading: new construction near the plant; vegetation growth; panel row-to-row inter-shading as panels age and mounting structures settle. Annual shadow analysis report recommended.

Step 3 — Inverter Availability Audit: OEM typically guarantees inverter availability above 98% over the contract period. Monthly downtime records per inverter — duration; nature (hardware failure; communication failure; grid fault protection tripping; firmware issue). Compare actual availability vs OEM guarantee. Where availability falls below guarantee — warranty claim must be filed within the timeline specified in the O&M contract.

Verify: warranty claims filed for all availability shortfalls; OEM response time compliance; spare parts availability at site (critical inverter components); firmware version current and OEM-certified.

Step 4 — Panel Condition and Degradation Audit: *Physical condition:* Annual EL (Electroluminescence) imaging — identifies micro-cracks; delamination; cell breakage; potential-induced degradation (PID); hot spots; verify last EL imaging date; findings; panels replaced or repaired. IV (Current-Voltage) curve tracing — annual test of each string; results vs nameplate Isc and Voc; strings showing significant deviation flagged. Thermal (IR) camera inspection — hotspot detection; bird dropping concentrations; mounting structure corrosion; cable insulation condition; junction box integrity.

Panel cleaning — frequency records; cleaning method (manual; robotic; rain-dependent); photographic evidence; water consumption log. For dusty locations (Rajasthan; Gujarat) — daily cleaning may be required to maintain PR above 80%. Soiling loss factor — compare PR before and after cleaning events.

Degradation tracking: Annual generation comparison normalised for solar irradiation — divide actual annual generation by annual irradiation from on-site pyranometer. Typical crystalline silicon warranted degradation 0.5–0.7% per year (Year 1 up to 2% allowed). If actual degradation exceeds warranted rate — panel OEM warranty claim available; file within the period stipulated in the purchase contract.

Step 5 — Metering and PPA Compliance: CEA (Installation and Operation of Meters) Regulations 2006 (as amended up to 2022) — energy meter at plant terminal (injection meter) must be of prescribed accuracy class; calibrated; sealed; last testing date within CEA-prescribed frequency; calibrated by NABL-accredited laboratory; sealed in presence of DISCOM/SLDC representative.

Auxiliary consumption sub-meter — verify AUX consumption is not inflated to reduce net generation; AUX should include only panel cleaning water pumps; lighting; monitoring systems; SCADA power.

Compensation for curtailment of RE for reasons other than grid security is payable by the procurer under the PPA and the Electricity (Promotion of Generation of Electricity from Must-Run Power

Plant) Rules, 2021. The claim must be raised on the procurer within the period specified in the PPA; disputes go to the appropriate Commission.

10.3 Wind Power Audit

10.3.1 Performance Parameters

Parameter	Formula / Definition	Benchmark (Indicative)	Key Audit Point
Turbine Availability	(Total hours − Downtime hours) ÷ Total hours × 100	OEM guarantees > 97% annually; below 95% for consecutive months — investigate and file warranty claim	Availability is distinct from generation; SLDC-curtailed turbine still counts as available for OEM warranty
Plant Load Factor (PLF)	Actual generation ÷ (Installed capacity × 8,760 hrs) × 100	25–35% depending on site; hub height; turbine class	P90 from wind resource assessment is the standard reference; consistently below P90 — investigate
P90 Generation	Generation level with 90% probability of being exceeded in any year, from wind resource assessment	Project-specific	Consistently below P90 = wind resource optimism or turbine under-performance; both are audit concerns

10.3.2 Audit Procedures — Wind Plant

Step 1 — Turbine Availability Audit: Monthly turbine availability — per turbine; per cluster; for the wind farm overall. Downtime classification is critical — downtime must be categorised as: Technical downtime (equipment fault — counts against OEM availability guarantee); Grid downtime (SLDC curtailment — does not count against OEM guarantee; triggers deemed generation claim); External downtime (force majeure — neither party's liability).

Verify downtime classification documentation — technical downtime must have maintenance work order or fault code from SCADA; grid downtime must have written SLDC curtailment instruction; any misclassification of technical downtime as grid downtime inflates apparent OEM availability.

Where technical downtime causes availability below OEM guarantee then warranty claim must be filed within the timeline in the O&M contract. Verify: claims filed for all availability shortfalls; OEM response records; pending claims; amounts claimed vs amounts settled.

Step 2 — SCADA-Based Generation Verification: Pull generation data from the wind farm SCADA for each turbine for the audit period. Compare per-turbine SCADA generation against: SLDC-certified energy injection at the grid connection point; PPA billing data to DISCOM; REC application data. Any systematic discrepancy between SCADA turbine-level data and grid-injection-level data requires explanation — normal system losses account for some difference; unexplained large differences indicate metering issues or data manipulation.

Downtime log from SCADA — verify downtime classification in billing records matches SCADA fault logs. SCADA records fault codes with timestamps; these are difficult to alter retrospectively and are the most reliable source.

Step 3 — Blade Maintenance Audit: Wind turbine blades are the most maintenance-intensive components and most critical for energy yield. Leading edge erosion — caused by rain; dust; insects — progressively reduces aerodynamic efficiency and energy output.

Annual blade inspection records — drone-based aerial inspection of each blade; erosion assessment by qualified blade inspector; damage catalogue with photographs and GPS coordinates. Blade repair records — leading edge protection (LEP) application; erosion coating; fibre repair; repair contractor qualification. Verify: last blade inspection date; findings; repairs completed vs findings; any blade replaced. Undetected or unrepaired blade erosion can reduce annual energy output by 2-5% — significant financial impact.

Step 4 — Wake Effect Analysis: In a wind farm, downstream turbines are in the wake (disturbed air) of upstream turbines. Wake losses are predictable from the wind resource assessment and the farm layout. Actual inter-turbine wake loss as measured from SCADA (ratio of downstream turbine generation to upstream turbine generation from the same wind direction) should be compared against the modelled wake loss in the DPR. Significantly higher actual wake losses than modelled may indicate: turbine yaw alignment issues; sub-optimal farm layout realised only in operation; or turbine performance problems.

Step 5 — Backing-Down Compensation: Compensation for curtailment of RE for reasons other than grid security is payable by the procurer under the PPA and the Electricity (Promotion of Generation of Electricity from Must-Run Power Plant) Rules, 2021. Verify: all SLDC curtailment instructions maintained in a dedicated register — date; time; duration; MW curtailed; instruction in writing from SLDC. Deemed generation computation — curtailed MW × duration × applicable tariff rate. The claim must be raised on the procurer within the period specified in the PPA; disputes go to the appropriate Commission. Any time-barred claims — quantify revenue loss.

10.4 Hydro Power Audit

10.4.1 What is Unique to Hydro Audit

Hydro power audit has several characteristics not found in any other generation technology:

Unique Feature	Description	Primary Audit Implication
Seasonal dependence	Generation tied to hydrology; monsoon surplus; lean-season (Mar–May) low generation	Year-to-year variance explained by CWC hydrology data; document clearly
Design Energy benchmark	Annual MU generation designed for 90% dependability hydrology; CERC tariff-recognised	Shortfall against Design Energy assessed by CERC in true-up; hydrology data is the defence
Reservoir Rule Curve	CWC/State-approved level	Rule curve violations — document reasons; flood cushion compliance during monsoon
Dam Safety Act 2021	Mandatory Dam Safety Unit; annual pre- and post-monsoon inspections; periodic comprehensive evaluation by an independent panel; EAP; instrumentation; non-compliance is	New statutory obligation; non-compliance cannot be treated as a merely technical gap

	a legal offence	
Silt management	Silt-laden water erodes turbine runners; guide vanes; desilting chambers; silt ejectors	Unmanaged silt causes 3–5% generation loss per year on silt-heavy rivers

10.4.2 Audit Procedures — Hydro Plant

Step 1 — Design Energy Achievement: Design Energy is the CERC-recognised generation benchmark for hydro plants which is expressed in Million Units (MU) per year. Actual annual generation compared against Design Energy and the resultant shortfall is assessed by CERC in the tariff true-up.

Hydrology variation — the most common explanation for generation shortfall. Obtain actual water inflows vs design hydrology from Central Water Commission (CWC) data or from the project's own hydrological monitoring. Where inflows were genuinely below 90% dependability levels — document clearly with CWC data; this explains the generation shortfall without tariff penalty.

Machine availability — actual turbine-generator unit availability; any prolonged forced outages reducing generation; maintenance scheduling — annual overhaul timing should avoid peak hydrology months.

Reservoir losses — evaporation; seepage from reservoir; these are standard losses incorporated in the Design Energy computation; verify actual losses are not significantly above design assumptions.

Step 2 — Reservoir Operations Audit: Rule Curve — obtain the approved rule curve (CWC or State water resources authority for the project). The rule curve specifies the reservoir level (Full Supply Level; Minimum Draw Down Level; and the mandated level at each date) that the project must maintain. Verify: actual reservoir level records — daily; compared against rule curve; any violation of rule curve — documentation of reasons; State water resources authority informed; any flood cushion compliance during monsoon.

MoU with Irrigation Department — many hydro projects have water sharing obligations with state irrigation departments (irrigation releases; minimum ecological flow; drinking water supply). Verify: actual water releases vs MoU obligations; any disputes with Irrigation Department; revenue implications of water sharing.

Flood cushion maintenance — the reservoir must be maintained below Full Reservoir Level during pre-monsoon and early monsoon to provide flood absorption capacity. Violation of the flood cushion — holding the reservoir too full when entering the monsoon — increases flood risk downstream. Verify flood cushion compliance.

Step 3 — Dam Safety Act 2021 Compliance: Dam Safety Unit — verify that the owner has constituted a Dam Safety Unit and that it has carried out the pre-monsoon and post-monsoon inspections of each specified dam every year, with inspection reports submitted to the State Dam Safety Organisation. Comprehensive dam safety evaluation — verify that a comprehensive safety evaluation has been carried out by an independent panel of experts at the intervals prescribed under the Act (generally every ten years, and after any extreme event or major incident), and that its recommendations are being implemented within agreed timelines. Verify: Dam Safety Unit constitution; last pre- and post-monsoon inspection reports; date and findings of the last comprehensive evaluation; status of open recommendations.

Emergency Action Plan (EAP) — documented for each dam; updated with current downstream population data; last mock drill date — should be annual; coordination with district administration; State Disaster Management Authority. Verify: EAP document currency; last mock drill; district administration coordination.

Dam instrumentation — piezometers (pore water pressure); settlement gauges; seepage measurement points; crack meters — all functioning and regularly read. Data recorded and analysed by dam safety monitoring team. Any adverse reading — unusual seepage increase; piezometer pressure rise; settlement must be investigated by the Dam Safety Unit and reported to the State Dam Safety Organisation.

Spillway gates — annual operational testing of all gates; gate operation records; hydraulic power pack maintenance; structural condition of spillway.

Step 4 — Silt Management: Silt ejectors — where installed (common in run-of-river projects on silt-heavy rivers); operational status; silt monitoring records upstream of intake; silt ejector efficiency. Turbine runner condition — annual inspection of all runners; erosion assessment by specialist; erosion rate measurement; runner replacement schedule. Runner erosion can reduce turbine efficiency by 3-5% per year on silt-heavy rivers — significant generation loss. Cross-verify silt concentration data against CWC published data for the river.

Desilting chambers — where provided in the project design; operational; periodic flushing of deposited silt; silt disposal.

Step 5 — Pumped Storage Plant (PSP) Specific: Pumped Storage Projects are a distinct sub-category of hydro; they consume electricity during off-peak periods to pump water to an upper reservoir and generate electricity during peak periods. Key parameters:

Round Trip Efficiency for PSP = (Energy generated by releasing water) ÷ (Energy consumed by pumping water) × 100. Typical PSP RTE is 75-80%. Verify monthly computation from metering data; compare against CERC-recognised RTE for the project.

Upper and lower reservoir levels — operational compliance; civil structure condition; any seepage or structural concern. CERC tariff for PSP — separate tariff for generation mode and pumping mode; billing to beneficiaries; pumping cost recovery mechanism. MoP Guidelines to Promote Development of Pump Storage Projects (2023) — verify compliance with policy provisions; any incentives being claimed.

10.5 Battery Energy Storage System (BESS) Audit

Grid-scale BESS is being deployed alongside RE projects under the Ministry of Power Order on Energy Storage Obligation dated 22 July 2022 and under SECI/state DISCOM procurement. The audit parameters and procedures for BESS are distinct from both thermal and RE generation.

10.5.1 Performance Parameters

Parameter	Definition	Benchmark (Indicative)	Key Audit Point
Round Trip Efficiency (RTE)	Energy output (discharge) ÷ Energy input (charge) × 100	Li-ion: 85–92%; below the OEM-guaranteed RTE — warranty claim	Degrades gradually with cycling; OEM RTE guarantee steps down each year

State of Charge (SoC)	Current charge as % of total capacity	Operating range 10–90% for Li-ion	BMS must enforce SoC limits; violation accelerates degradation
Cycle Count	Cumulative complete charge-discharge cycles from commissioning	OEM warranty: typically 4,000 equivalent full cycles or years, whichever first	Track cumulative cycles vs OEM warranty threshold
Available Capacity	Actual available MWh vs nameplate; annual capacity test	Typical Li-ion: 2–3% loss/year; OEM warranty: not > 20% loss over warranty period	Capacity loss exceeding warranted degradation — warranty claim triggered

10.5.2 Audit Procedures — BESS

Step 1 — RTE Verification: Monthly energy metering — energy input at charging meter (kWh charged) and energy output at discharging meter (kWh discharged). Both meters must be independent certified meters and should not be calculated from a single meter. RTE = kWh discharged ÷ kWh charged. Compare against OEM-guaranteed RTE for the relevant year of operation (OEM RTE guarantee typically steps down each year as warranted degradation is factored in).

BMS software — verify current firmware version is OEM-approved and current; last update date; OEM certification of update. BMS controls the charge/discharge profile; incorrect BMS configuration can cause both safety risks and performance degradation.

Where RTE is consistently below OEM guarantee — file warranty claim; also investigate thermal management of the battery enclosure (high ambient temperature accelerates degradation); verify BMS SoC limits are being enforced.

Step 2 — Capacity Degradation Tracking: Annual capacity test — conducted in presence of OEM representative; test methodology as per IEC 62620 or the method specified in the supply contract; actual available capacity determined. Year-wise capacity tracking — compare against OEM warranted degradation curve. Where actual capacity is below OEM warranted curve then warranty claim is available.

Ind AS 36 Impairment — where the BESS is degrading faster than warranted and OEM warranty claim is unlikely to be sustained or is disputed, the impairment of the BESS asset must be considered. Carrying value in books vs recoverable amount (value in use based on remaining capacity and contract revenues) — impairment provision may be required.

Step 3 — Charging Source Audit — Critical for REC: This is the most important technical audit point specific to BESS and has direct revenue implications through REC eligibility:

BESS charged from the RE component of the project — energy discharged is eligible to carry RE attribute; RECs can be applied for on this energy. BESS charged from the grid (non-RE source)- energy discharged does NOT carry RE attribute; RECs cannot be applied for on this energy.

Independent metering of charging source is non-negotiable. A single combined meter at the BESS AC terminal cannot distinguish RE-sourced from grid-sourced charging. Verify: physical existence of separate charging source meters; calibration records; metering scheme approved by DISCOM/SLDC; BMS records of charging source vs metered data cross-verification.

Absence of independent charging source metering is a fundamental audit finding — REC eligibility for BESS-discharged energy cannot be established and all REC claims may be challenged.

Step 4 — ESO-Linked Contracts: Where BESS capacity is contracted to an obligated entity for its Energy Storage Obligation, verify that contracted capacity, availability and energy delivered meet the contract terms on which the obligated entity relies; any shortfall is a contractual penalty exposure for the BESS owner.

Step 5 — Fire Safety and Thermal Management: Li-ion batteries carry thermal runaway risk as a cell failure can propagate and cause fire. This is an active safety concern with several incidents documented internationally.

Fire detection and suppression system — FM200 or equivalent; commissioned; last tested; records. Thermal management system — HVAC maintaining enclosure within OEM-specified temperature range; temperature monitoring alarms. BMS thermal runaway detection — cell-level temperature monitoring; emergency disconnect triggers. Fire NOC from State Fire Department — valid; conditions complied with. Last fire drill — records; personnel trained in BESS fire response (BESS fire response must follow the OEM's emergency response plan and NFPA 855 or the applicable Indian standard; gaseous agents alone do not stop thermal runaway, and personnel must be trained in the specific response for the installed system).

10.6 REC (Renewable Energy Certificate) Audit

RECs represent a significant revenue stream for RE GENCOs and are traded on power exchanges. Errors in REC registration; application; or trading result in material and often irrecoverable revenue loss because REC applications have a 180-day deadline from the generation month.

Step 1 — REC Registry Registration: Verify the RE plant is registered with NLDC's REC registry — registration certificate; registration number; eligible technology category. Eligibility conditions — verify the plant meets REC eligibility criteria: commissioned after specified date; does not avail ISTS waiver concurrently with REC (some configurations are incompatible); does not avail accelerated depreciation in combination with REC in certain legacy configurations. Any eligibility question must be resolved before filing applications.

Step 2 — Monthly REC Application: Generation data for REC issuance must be SLDC/RLDC-certified generation data; not self-reported plant data. Monthly REC application to NLDC — within 180 days of the generation month. Create a generation-wise application tracker: month of generation; generation units; application date; whether within 180-day window; RECs issued; any shortfall between generation and RECs issued — investigate reason.

Time-barred applications — generation months for which REC application was not filed within 180 days are permanently time-barred; no extension is available. Quantify revenue loss: time-barred units × prevailing REC price.

Step 3 — REC Trading: Under the CERC REC Regulations 2022, RECs are traded on IEX, PXIL and HPX at market-determined prices (floor and forbearance prices were abolished) and remain valid until sold. Trading strategy — Board-approved; when to sell versus hold. Settlement — exchange settlement advices for each session; bank credits; reconciliation with books.

REC inventory accounting — carrying value in books; NRV assessment where market price is below carrying value. Revenue recognition under Ind AS 115 — revenue is recognised when the REC is sold and the trade is settled, not when it is issued.

Financial Impact Formula: REC revenue lost due to time-barred applications = Time-barred generation units × prevailing REC market price (exchange clearing price).

10.7 RE Project Finance Interface Audit

Most RE projects are project-financed with ring-fenced cash flows; specific lender conditions; and Independent Engineer oversight. The project finance structure creates ongoing audit obligations throughout the project's life, not just at financial closure.

Step 1 — DSRA (Debt Service Reserve Account): Required DSRA balance, typically 1 to 3 months of debt service as specified in the loan agreement. Verify actual DSRA balance from bank statement as at each month end; compare against required balance. Where actual balance falls below required — lender notification obligation; cure period (typically 30 days to replenish); verify notification was given and cure was effected within the period. Uncured DSRA shortfall is an Event of Default in most project finance agreements.

Step 2 — DSCR (Debt Service Coverage Ratio): Quarterly DSCR computation — (Cash Available for Debt Service during the quarter) ÷ (Debt Service due in the quarter). Cash Available = EBITDA − Capex − Changes in Working Capital − Taxes. Minimum DSCR covenant — typically 1.10 to 1.20 as specified per loan agreement. Where DSCR falls below the minimum covenant level — lender notification required; waiver may be needed; step-up of security or cash sweep may be triggered. Compute and verify quarterly DSCR.

Step 3 — Independent Engineer Reports: IE is appointed by the lenders and periodically visits the project during both construction and operation. IE reports are authoritative independent technical assessments and are valuable audit intelligence — refer Section 4.14.

Obtain IE reports for the audit period — any critical observations; management response to critical observations; action taken and timeline. IE certification for loan drawdowns — during construction; drawdown is typically linked to IE certification of milestone achievement; verify no drawdown made without corresponding IE certification.

Step 4 — Conditions Subsequent: Loan agreement Conditions Subsequent — items the borrower committed to complete after financial closure within specified timelines. Track completion status: any condition pending beyond its deadline is a potential Event of Default. Common Conditions Subsequent: insurance policies — all policies in place and assigned to lenders; all permits and approvals obtained; environmental and forest clearance conditions — Stage II FC; hedging arrangements in place.

Step 5 — Cash Waterfall Compliance: Project finance loan agreements typically prescribe a cash waterfall — the priority order in which project revenues are applied: operating expenses first; debt service second; DSRA replenishment third; distribution to equity last. Verify: actual cash flow waterfall as applied each month corresponds to the contractual waterfall; no distributions to equity made when DSRA is below required level or debt service is not current.

10.8 Green Hydrogen — Audit Reference Framework

Green hydrogen production is in early commercial deployment under MNRE's National Green Hydrogen Mission 2023 and SIGHT programme. The following audit framework applies:

SIGHT Incentive Accounting: MNRE's SIGHT programme provides financial incentives for green hydrogen and green ammonia production. Verify: incentive eligibility — production volumes; GHG

intensity thresholds; MNRE-approved methodology; incentive computation — correct rate; correct eligible production quantity; incentive accounted in books as government grant per Ind AS 20 — deferred until conditions are met.

Electrolyser Capitalisation: Electrolyser systems are capital assets. Verify: correct capitalisation timing — COD; component-wise capitalisation; depreciation rate applied; maintenance cost vs capital improvement — correct classification. Electrolyser efficiency — kWh per kg of hydrogen produced — tracked; compared against OEM specification; degradation monitoring.

PESO Approvals for Hydrogen Storage: Hydrogen is a flammable gas requiring PESO (Petroleum and Explosives Safety Organisation) approval for storage and handling. Verify: PESO licence — valid; conditions complied with; hydrogen storage vessel certification — PESO-approved design; pressure vessel inspection records; hydrogen safety management plan.

Green Certification — Source Verification: Hydrogen is classified as "green" only if produced by electrolysis using electricity from RE sources. Metering must establish that the electricity used for electrolysis is RE-sourced — either from a dedicated RE plant or from a certified RE power purchase. Verify: metering scheme distinguishes RE-sourced electricity from grid electricity; green hydrogen certification from accredited certifying body; any carbon credit claim linked to green hydrogen — MRV plan compliance.

Offtake Agreement Compliance: Revenue recognition per Ind AS 115 — revenue on delivery of hydrogen meeting specification. Verify: hydrogen purity testing — BIS/ISO standards for each delivery; non-conforming deliveries — quality rejection provisions; take-or-pay provisions — minimum offtake obligations; any shortfall penalties.

Note: Section 4.5.1 covers forthcoming regulatory developments for green hydrogen. Internal auditors should monitor MNRE and BEE notifications for updates to the compliance framework.

10.9 Nuclear Power — Brief Reference

Nuclear power operates under a fundamentally distinct framework — the Sustainable Harnessing and Advancement of Nuclear Energy for Transforming India Act, 2025 (SHANTI Act), the statutory regulatory framework administered by the Atomic Energy Regulatory Board (AERB) and applicable international safeguards obligations, including those arising under India's agreements with the IAEA. NPCIL is the principal nuclear power operator, presently operating 24 commercial nuclear power reactors across seven sites, with an installed capacity of 8,780 MW as at August 2026 (excluding RAPS-1). AERB directions are non-negotiable operating conditions; no internal audit finding or management decision can override an AERB direction. Safety culture — not mere compliance is the foundational operating principle; any audit finding touching on safety must be assessed for its safety implication first, before its financial or compliance dimension.

Key Audit Areas

Audit Area	Key Audit Points
AERB Operating Licence	Compliance with all licence conditions; periodic safety reviews on schedule; deviations reported to AERB within prescribed timelines; AERB directions implemented
Nuclear Fuel Management	Procurement against approved fuel cycle plans; physical inventory at all stages (in-core; in-pond; in-transit); AERB fuel accounting and IAEA safeguards reporting — any discrepancy is a matter of national security, not

	a routine audit finding
Capital Expenditure	Reactor life extension; uprating; safety upgrades require AERB technical clearance at each stage; capitalisation without AERB clearance is both a regulatory violation and a tariff risk
Radiation Monitoring	Cumulative dose records for every worker (permanent and contract) who enters the controlled area; maintained for working life; AERB annual dose limit compliance; mandatory medical examinations
Emergency Preparedness	On-Site Emergency Plan currency; coordination with district administration Off-Site Emergency Plan; periodic AERB-mandated drills; Emergency Response Centre equipment and staffing

Reporting Considerations: Internal audit reports on nuclear facilities carry heightened confidentiality — distribution restricted to CMD, Director (Operations), CIA, and Audit Committee. Safety findings communicated separately to the plant's Safety Committee. MAFR entries for nuclear facility findings must track AERB response status as a separate column. Auditors must refer to AERB regulations and NPCIL internal audit guidelines — these are not covered further in this Guidance Note.

10.10 Fraud Risk Indicators — RE GENCO

Fraud Scheme	How It Works	Detection Procedure
Generation under-reporting in books	Actual generation higher than booked — lower revenue recognised; excess cash from billing not reflected in books	Cross-verify SCADA generation against SLDC-certified energy; bank credits from DISCOM vs billed amount; surprise meter reading
Injection meter tampering	Meter records lower generation than actual — DISCOM billed for less; difference pocketed by plant staff in collusion with DISCOM meter reading staff	Surprise independent meter reading during audit; compare with SCADA; CEA-prescribed meter testing — pull last test date
REC double-claiming	Same generation units used for multiple REC applications in different months or across different NLDC registrations	NLDC REC registry reconciliation — generation applied for vs SLDC-certified generation; verify no generation month appears in two applications
False deemed generation claims	Backing-down claim filed without actual SLDC instruction — revenue claimed for curtailment that did not occur	Cross-verify every deemed generation claim against written SLDC instruction with timestamp; SLDC scheduling records
BESS charging source misrepresentation	Grid-charged BESS energy presented as RE-charged — REC applied for on ineligible energy	Independent charging source meter data vs BMS logs; RE generation during charging period vs BESS charge level
Solar panel cleaning records falsified	Cleaning not conducted but records show cleaning done — soiling losses higher than they should be; cleaning staff wages	Surprise inspection of panel surface soiling condition vs cleaning records; soil deposit photographs; water consumption records vs cleaning frequency claimed

Fraud Scheme	How It Works	Detection Procedure
	paid fraudulently	
Wind turbine downtime misclassification	Technical downtime (OEM warranty liability) reclassified as grid downtime — OEM warranty claims avoided; OEM fee arrangement	SCADA fault code cross-verification; SLDC curtailment instruction register vs classified downtime register
OEM warranty claim suppression	Valid warranty claims not filed — O&M manager has undisclosed arrangement with OEM	Independent comparison of actual performance vs OEM guarantee; all valid claims verified as filed; O&M manager conflict of interest check

11. TRANSCO AND LOAD DESPATCH CENTRE AUDIT

11.0 Introduction

Transmission companies (TRANSCOs) and Load Despatch Centres (LDCs) are critical national infrastructure entities and have a fundamentally different business model from GENCOs and DISCOMs. They earn regulated returns on their infrastructure without fuel cost, without commercial revenue risk from consumers, and without the generation performance uncertainties that characterise GENCO audit. Their audit risks concentrate in capital works and capitalization timing; transmission tariff billing accuracy; transmission loss management; OT and SCADA cybersecurity; system operation charges; grid incident documentation; and physical security of critical infrastructure.

TRANSCO audit and LDC audit are covered in the same chapter because in many state utilities the State Transmission Utility (STU) and State Load Despatch Centre (SLDC) functions are organisationally combined within the same entity. Where they are separate entities as in the case of PGCIL and Grid-India at the national level then each section is independently applicable to the relevant entity.

Generic procurement and capital works procedures are covered in Chapter 14. This chapter covers the TRANSCO and LDC-specific additions — CERC prudency requirements for transmission assets; Right of Way; tower foundation audit; SCED compliance; scheduling and energy accounting; ancillary services; REC registry operations; and grid incident management.

11.1 Red Flag Dashboard — TRANSCO and LDC

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
1	Transmission system availability below normative	Below 98% for two or more consecutive months	Transmission charge recovery loss; CERC/SERC notice; potential disincentive
2	Capital works cost overrun above 15%	Cost overrun above 15% of Board-approved estimate	CERC prudency disallowance risk; contract management failure
3	Transmission tariff billing delayed	Any billing cycle delayed beyond 45 days	Revenue leakage; time value loss
4	ISTS charges unreconciled for two months	Monthly ISTS charges unreconciled with NLDC/CTUIL computations for more than 2 months	Financial exposure; billing disputes with CTUIL
5	OT/SCADA cybersecurity VAPT overdue	Annual VAPT by CERT-In empanelled agency not conducted	CEA Cyber Security Guidelines 2021 violation; CII non-compliance
6	GNA connectivity queue not tracked	No register of pending GNA applications and status	Connectivity revenue delay; CERC compliance gap
7	Transformer failure rate above norm	More than 2% annual failure rate for power transformers	Maintenance quality concern; asset management failure
8	SCED non-compliance reported by NLDC	Any month with SCED deviation penalty imposed	CERC penalty; grid reliability concern

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
9	DSM settlement amounts unreconciled beyond 30 days	DSM payable or receivable outstanding beyond 30 days	Revenue leakage; counter-party risk
10	Major maintenance contract without performance guarantee	Any capital R&M contract above Rs. 5 crore without PG	Financial exposure on poor contractor performance

11.2 Transmission Tariff Audit

11.2.1 Annual Transmission Charges — Billing and Recovery

The transmission tariff under CERC Tariff Regulations 2024-29 comprises Annual Transmission Charges (ATC) approved by CERC or the SERC. For the ISTS, charges are shared among designated ISTS customers under the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations 2020: NLDC, as Implementing Agency, computes each customer's share, and CTUIL raises the bills and passes collections to transmission licensees. For intra-state systems, ATC is shared among STU users as approved by the SERC.

Components of Transmission Tariff under CERC 2024-29:

Component	Basis (Indicative)	Key Audit Point
Return on Equity (ROE)	15.5% on equity; grossed up for applicable tax rate	Equity amount; tax rate applied; grossing up computation
Depreciation	CERC-prescribed schedule by asset type	Asset-wise computation; COD accuracy; no pre-COD depreciation
O&M Expenses	CERC normative per circuit km (lines) and per bay (substations); indexed for inflation	Actual vs normative; year-on-year trend; items typically disallowed
Interest on Loan	On normative debt — 70% of admitted capital cost; at the weighted average rate of the actual loan portfolio	Loan schedule; actual vs normative debt; interest computation
Interest on Working Capital	At SBI one-year MCLR plus 350 basis points (Appendix A1.5)	WC components; normative computation; SBI rate applied

Step 1 — Monthly Billing: Verify that monthly bills match the NLDC (Implementing Agency) computation for each customer; that bills are raised within the month by CTUIL (ISTS) or the STU (intra-state); and that any revision is supported by a Commission order.

Step 2 — Recovery Tracking: Outstanding transmission charges — aging analysis: 0-30 days; 31-60 days; 61-90 days; above 90 days. Interest on delayed payment — SBI rate plus margin as prescribed in CERC Regulations; computation; billing; recovery. Payment security — where beneficiary fails to pay beyond 2 months; LC/escrow adequacy verification monthly as per TSA/PPA terms; adjudication by CERC under Section 79(1)(f) or the SERC under Section 86(1)(f) of Electricity Act, 2003 available where payment security is breached. Write-offs — any transmission charges written off; Board approval; CERC implications for tariff — receivables written off in the books are generally not recoverable through tariff and should be examined for the underlying cause, approval, recovery efforts and any regulatory implications.

Step 3 — ISTS Charges Reconciliation with NLDC and CTUIL: NLDC computes the monthly ISTS charges of each designated ISTS customer and CTUIL bills them. For a transmission licensee,

verify that the amounts CTUIL passes on match its approved ATC; for GENCOs or DISCOMs, verify that CTUIL's bills match NLDC's computation; raise any discrepancy with CTUIL/NLDC; track resolution.

Step 4 — ISTS Waiver for RE Projects: MoP orders have extended the waiver of ISTS transmission charges and losses for RE projects — full waiver to 30 June 2025, then reducing 25% a year to June 2028. Verify: RE projects entitled to waiver are correctly identified in NLDC computations; waiver is applied correctly — no charging of ISTS transmission charges to eligible RE projects; where waiver lapses (project ceases to be eligible or waiver period ends), charges commence from correct date. Financial impact of waiver — waived charges are pooled and recovered from non-eligible users through a loading factor; verify pooling and recovery mechanism.

11.2.2 True-Up Petition Audit

Similar to GENCO true-up in Section 8.5, transmission companies also file true-up petitions with the SERC annually, or with CERC at the end of the control period. Pre-filing review by internal audit adds significant value.

Capital Cost: Verify against fixed asset register; no assets unrelated to transmission included; capitalization timing — COD of each new element; no premature capitalization of lines or substations before commissioning.

O&M Cost: Actual vs CERC normative per circuit km and per bay; items typically disallowed by CERC — penalties; donations; non-transmission related costs; costs of social activities.

Actual vs Normative Debt: If actual debt is above 70% of admitted capital cost — interest on the excess is not recoverable. Compute normative debt vs actual debt; verify that the interest claim uses the weighted average rate of the actual loan portfolio.

Transmission Availability: Monthly availability for each transmission element — lines and substations. Normative availability is 98%. Incentive computation for above-norm availability or disincentive for below-norm availability — verify formula and inputs are consistent with CERC Regulations.

11.3 Transmission Loss Audit

ISTS losses are computed by NLDC and borne by users in kind under the CERC Sharing Regulations 2020; for intra-state systems, the SERC specifies a loss trajectory for the STU. A TRANSCO does not buy energy, so excess losses fall on its users — ultimately DISCOMs — and indicate network inefficiency that the SERC may consider in performance assessment and in the DISCOMs' approved power purchase.

Monthly Energy Accounting: Energy injected into the transmission system at generating stations and import points (in MWh) minus energy drawn from the transmission system at delivery points to DISCOMs and export points = Transmission Losses. Transmission loss% = Losses ÷ Injected energy × 100.

Audit Procedures: Obtain monthly energy accounting statements for the audit period — injection data from generating stations/import points and delivery data at DISCOM/export boundary points. Cross-verify injection and drawal data with SLDC/RLDC energy accounts, schedules and interface/ABT meter readings, as applicable.

For intra-State transmission, compare actual transmission loss against the SERC-approved transmission-loss trajectory/target for the relevant year. Analyse deviations and identify persistent or material excess losses. For ISTS transactions, verify loss accounting and settlement in accordance with the applicable CERC sharing and loss-allocation framework rather than applying an intra-State normative-loss benchmark.

Identify high-loss lines/substations through energy accounting and load-flow analysis and correlate abnormal losses with loading, voltage profile, reactive-power flow, equipment condition, metering accuracy and maintenance records.

Indicative Financial Impact — Intra-State Transmission:

Excess transmission loss cost = (Actual transmission loss % − SERC-approved transmission-loss target %) × Total energy input ÷ 100 × applicable average energy cost.

The resulting amount represents an indicative economic impact of losses above the approved trajectory and should not automatically be treated as a tariff disallowance unless so determined by the SERC.

11.4 Capital Works Audit — Transmission Specific

Generic procurement and capital works procedures are covered in Chapter 14. The following are TRANSCO-specific additions that arise from the nature of transmission assets and CERC prudency requirements.

11.4.1 Right of Way (RoW) for Transmission Lines

RoW is the legal right to construct and maintain transmission towers and lines across private and government land. RoW acquisition is frequently the most significant and most contentious aspect of transmission project implementation in India. Delays in RoW acquisition have caused more transmission project delays than any other single factor.

Audit Procedures: RoW compensation — compensation paid to landowners and affected parties must be as per the MoP guidelines on RoW compensation (as revised in 2024) adopted by the State Government, and the RFCTLARR Act where land is acquired. Verify: compensation computed at correct rate; payments made to correct beneficiaries through bank transfer; any RoW compensation disputes — court cases filed by landowners; pending cases; provisions made.

RoW dispute impact on project timeline — where RoW disputes have caused line commissioning delay; compute the financial impact: delay in commissioning × monthly ATC entitlement foregone. Assess whether CERC/SERC petition for time extension or compensation has been filed.

Encroachment on existing RoW — periodic survey of existing transmission corridors for encroachment — constructions within the safety corridor; vegetation grown into the safe clearance zone; verify survey frequency; encroachment records; action taken for removal.

11.4.2 Tower Foundation and Line Quality

Tower foundation quality is critical for transmission line safety and longevity. Foundation failure can cause tower collapse, loss of power supply, and safety risks.

Audit Procedures: Geotechnical investigation — verify that soil testing was conducted at each tower location before foundation design, that soil test reports are available, and that the foundation

type matches the soil bearing capacity. Tower foundation quality — third-party quality inspection during construction; concrete cube strength test results; any foundation repairs; records.

Stub setting accuracy — the stub, the embedded steel member that connects the tower to the foundation must be set at the correct position and angle; incorrect stub setting causes tower misalignment and structural stress. Verify third-party inspection of stub setting during construction.

Tower erection and stringing — quality inspection records for tower assembly; conductor stringing tension; sag measurement records.

11.4.3 Substation Equipment Audit Points

Power transformers — procurement specification; testing at manufacturer (factory acceptance test — FAT); FAT records; transformer oil quality test on receipt; nameplate rating vs specification; any transformer breakdown in recently commissioned substations — warranty claim filed; protection relay testing records — differential; overcurrent; earth fault; distance relay settings.

Protection coordination — protection system design must ensure that faults are cleared without cascade tripping. Annual relay testing records; settings review by qualified protection engineer; any protection failure events — post-event analysis.

Bus protection and circuit breaker maintenance — annual maintenance of all circuit breakers; SF6 gas pressure monitoring; operating counter vs maintenance interval; SF6 leak detection.

11.4.4 TBCB SPV Specific Audit Points

For transmission projects executed through Tariff Based Competitive Bidding SPVs:

CERC transmission licence — valid; conditions complied with; Letter of Award conditions from the bidding process — project schedule compliance; any liquidated damages for delay. Revenue commencement — from actual COD; billing from the correct date; no billing before transmission element is commissioned and tested.

Lender interface — TBCB SPVs are project-financed; IE reports; DSRA; DSCR; Conditions Subsequent — apply same procedures as Section 10.7 for project finance audit.

11.5 SCED Audit

Security Constrained Economic Despatch (SCED) is operated by NLDC for all ISTS-connected thermal generating stations. SCED despatches generating stations in merit order i.e. cheapest first subject to transmission security constraints, thereby minimising the overall cost of power while maintaining grid security. SCED was introduced as a pilot from 1 April 2019 for inter-state coal-based stations whose tariff is determined by CERC, and its scope has since been extended by CERC orders.

For TRANSCOs: SCED instructions from NLDC prescribe a daily despatch schedule taking into account transmission network constraints. Where the TRANSCO's network has congestion — specific lines overloaded then NLDC modifies the despatch schedule to relieve congestion. Verify: TRANSCO's network data (line capacities; transformer ratings; impedance) submitted to NLDC for SCED computation is accurate and current; any network data discrepancy that caused SCED to produce sub-optimal solutions — identified and corrected; congestion attributed to TRANSCO network weakness — remedial action plan; timelines.

For SLDCs: where a state has adopted SCED- or merit-order-based optimisation for intra-state generators, verify that despatch follows the approved methodology; any deviations from SCED are documented with technical justification; SCED-based redespatch cost computation — costs passed through correctly to the responsible parties.

Financial Impact of SCED Non-Compliance: CERC may impose penalty for non-compliance with SCED by the responsible entity — generator or system operator. Verify: any CERC SCED non-compliance notices received; penalty paid; corrective action taken; representation filed if penalty is disputed.

11.6 NLDC/RLDC/SLDC Audit Framework

11.6.1 System Operation Charges

LDCs earn system operation charges which are approved annually by CERC (for NLDC/RLDC) or SERC (for SLDC) for the service of operating the grid. These charges are billed to generators and buyers connected to the system.

Audit Procedures: System operation charges approved for the year — verify approval order; breakdown of system operation charges by component. Monthly billing to each user — correct proportion; timely billing; recovery aging analysis; interest on delayed payment; any disputed charges — resolution; CERC/SERC filing if dispute not settled bilaterally.

REC registry fees (NLDC) — fees charged for REC issuance; registry services; trading infrastructure — approved fee schedule; billing accuracy; recovery tracking.

11.6.2 Scheduling and Energy Accounting Audit

This is the core operational function of LDCs and the primary audit area. Scheduling accuracy and DSM settlement accuracy directly affect the financial positions of all generators and buyers connected to the grid.

Day-Ahead Schedule vs Real-Time Despatch: Obtain the day-ahead schedule for each generating station in the RLDC/SLDC region for the audit period — on a sample of days. Compare with actual generation data from SCADA/ABT meters for the same period. Deviations between scheduled and actual generation trigger DSM settlement. Systematic scheduling errors where the schedule consistently differs from actual in a predictable direction for specific generators may indicate gaming of the scheduling system.

DSM Settlement Computation: Deviation charges are computed for each 15-minute time block under the CERC DSM Regulations, at rates linked to market clearing prices. The weekly DSM accounts are issued by the Regional Power Committee secretariat, and the deviation pool is operated by the RLDC.

Verify: deviation volumes computed correctly from ABT meter readings; rates applied are those specified in the Regulations for that block; DSM amounts payable and receivable computed correctly; amounts agreed with the RPC accounts; amounts paid and received within stipulated period.

DSM Register: Maintain a running register of all DSM transactions — payable; receivable; net position month-by-month; reconciliation with the RPC accounts and the RLDC pool statements. Any unreconciled items — aged analysis; follow-up.

ABT Meter Data Accuracy: ABT (Availability Based Tariff) meters at the grid connection point of each generating station are the basis of all energy accounting. Verify: ABT meters are CEA-compliant; sealed; calibrated within prescribed period; sealed in presence of RLDC/SLDC and GENCO representatives; any meter replacement — due process; readings from both old and new meter reconciled; any period of meter failure — energy accounting for that period using prescribed fallback methodology.

Red Flags: DSM charges paid consistently lower than expected given observed deviation volumes — computation error risk; generator consistently declaring very high capacity (higher than past performance suggests) to maximise capacity charge; SLDC scheduling data systematically inconsistent with RLDC data at the state boundary — energy accounting discrepancy between state and regional accounts.

11.6.3 Ancillary Services Audit (NLDC)

NLDC procures ancillary services from eligible generators to maintain grid frequency within the prescribed band (49.9-50.05 Hz under the IEGC 2023) and CEA (Grid Standards) Regulations.

Procurement: Under the CERC Ancillary Services Regulations 2022, Secondary Reserve Ancillary Services (SRAS) are provided through Automatic Generation Control and Tertiary Reserve Ancillary Services (TRAS) are procured through the market mechanism; primary response is a mandatory IEGC obligation. Verify: provider eligibility; compensation computed as specified in the Regulations; market clearing records for TRAS.

Activation and Payment: Ancillary services activated in a given month — NLDC activation records; quantity activated per provider; payment at approved rate; total payment to ancillary service providers. Recovery from beneficiaries — cost pooled among ISTS users; billing and recovery.

Settlement Reconciliation: NLDC settlement statement for ancillary services — each provider's statement; payment received vs NLDC records; any disputes — resolution process.

11.6.4 REC Registry Operations — NLDC

NLDC operates the Renewable Energy Certificate (REC) registry — the authoritative platform for REC issuance; management; trading; and redemption.

REC Issuance Accuracy: When a RE generator applies for RECs — submitting SLDC-certified generation data — NLDC issues RECs based on the submitted data after internal validation. Verify: NLDC validation process — does it cross-check applicant's submitted generation against SLDC records independently?; any instances of RECs issued in excess of SLDC-certified generation — risk of double-counting.

Registry Integrity: Audit trail of all REC issuances; cancellations (on redemption for RPO compliance); and trading transactions — complete; tamper-resistant; no instances of RECs being resurrected after cancellation; registry system access controls, only authorised NLDC staff can issue or cancel; activity log reviewed.

Fee Collection: Registry fees — per REC issued; per trading transaction; billing; recovery; any fee arrears.

Cybersecurity of Registry: The REC registry is critical financial market infrastructure. Unauthorised modification of registry records could have significant financial impact on RE

generators and obligated entities. Verify: registry hosted on secure infrastructure; access controls; penetration testing; backup; disaster recovery for registry data.

11.6.5 Grid Incident Management Audit

When a major grid disturbance occurs — frequency collapse; regional islanding; transmission line fault causing cascade tripping; blackout then the LDC is required to manage the restoration and prepare a formal post-event analysis.

Post-Event Analysis: Verify: post-event analysis report prepared within prescribed period (typically 7 days for a major event); report contains — sequence of events with timestamps; cause analysis; protection system performance; communication failures if any; restoration procedure followed; time to restoration.

CERC/SERC Reporting: Grid disturbance report submitted to CERC/SERC within 7 days of the event — format prescribed by CERC; contents matching post-event analysis; any CERC/SERC observations on the event — compliance actions.

Black Start Capability: Black start — the ability to restore the grid after a total blackout using generating units that can start without external power supply is a critical grid resilience requirement. Verify: black start generators identified and contracted; last black start test date — CERC/IEGC prescribes periodic testing; test result and observations; any remediation of black start deficiencies.

Lessons Learned: Verify that grid incidents are reviewed systematically and that lessons are built into operating procedures — lessons learned register; procedure revisions; training conducted.

11.7 OT/SCADA Cybersecurity Audit

Transmission companies and LDCs operate Energy Management Systems (EMS) and SCADA systems that are among the most critical OT (Operational Technology) systems in the country. These systems control real-time grid operation and are designated as Critical Information Infrastructure (CII) by NCIIPC. A cybersecurity breach in an EMS or SCADA system could cause cascading power failures affecting millions of consumers and critical services.

Applicable framework: CEA Cyber Security Guidelines 2021; CERT-In Directions 2022; IEC 62443; IT Act 2000 Section 70 etc.

Step 1 — Annual VAPT: Vulnerability Assessment and Penetration Testing (VAPT) must be conducted annually by a CERT-In empanelled agency. Verify: VAPT conducted in the last 12 months; agency is currently empanelled by CERT-In; VAPT scope covers EMS; SCADA; communication network; remote access systems; VAPT report — critical findings; remediation status; re-testing of critical findings after remediation.

Step 2 — IT-OT Network Segmentation: The EMS/SCADA network (OT network) must be physically or logically isolated from the corporate IT network. A breach in the corporate network should not provide access to OT systems. Verify: network architecture diagram — shows clear separation between IT and OT zones; firewall rules between IT and OT — reviewed and updated; no direct connectivity between corporate email/internet zone and OT zone; data diode or one-way gateway where data must flow from OT to IT for reporting purposes.

Step 3 — Remote Access Controls: Remote access to OT systems — for vendor maintenance; NLDC coordination; remote monitoring must be strictly controlled. Verify: all remote access sessions require prior approval; two-factor authentication mandatory for all remote access to OT

systems; session duration limited and automatically terminated; all sessions logged with timestamp; user identity; actions performed; vendor access — vendors must not have persistent access; access granted only for specific maintenance window.

Step 4 — Patch Management for OT Systems: OT systems — SCADA servers; EMS workstations; RTUs (Remote Terminal Units); PLCs (Programmable Logic Controllers) run specialised software that cannot be patched as frequently as corporate IT systems. However, critical security patches must be applied. Verify: patch management process for OT systems — assessment of each patch; OEM certification that patch does not affect system functionality; test environment before production; rollback plan; any OT systems running on end-of-life operating systems (instances of Windows XP and Windows Server 2003 have been documented in the Indian power sector; these have no vendor security support); risk acceptance if patch cannot be applied.

Step 5 — Supply Chain Security: Government of India has issued orders restricting import of equipment from certain countries for critical infrastructure. For power sector — equipment from specified countries requires security clearance. Verify: all installed EMS; SCADA; RTU; communication equipment — country of origin; any equipment from restricted country — government security clearance obtained; equipment firmware integrity — no unauthorised firmware; supply chain audit of critical equipment OEMs.

Step 6 — IEC 62443 Compliance: IEC 62443 is the international standard for Industrial Automation and Control System (IACS) security. It prescribes a zone and conduit security model — dividing the OT network into security zones with defined security levels; communication between zones through controlled conduits. Verify: IEC 62443 zone classification of TRANSCO/LDC OT environment; conduit security — only authorised protocols and ports between zones; security level target vs security level achieved for each zone.

Step 7 — CERT-In Directions 2022 Compliance: Verify: 6-hour mandatory reporting of cybersecurity incidents to CERT-In — any incidents in the audit period; were they reported within 6 hours? 180-day log retention — ICT system logs; network logs; application logs — retained for 180 days minimum; NTP server synchronisation — all OT systems synchronised to NTP server; synchronised to NIC or NPL NTP servers.

Step 8 — Incident Response: Cybersecurity Incident Response Plan (CIRP) — documented; tested; CERT-In notification procedure included; escalation to NCIIPC as CII operator; last tabletop exercise date; lessons incorporated from exercise. Any cybersecurity incident in the audit period — timeline of detection; containment; recovery; CERT-In notification timeliness; post-incident review.

Red Flags: OT systems running end-of-life operating systems without formal risk acceptance; vendor remote access sessions not logged or session not terminated after maintenance; equipment from restricted countries installed without security clearance; VAPT not conducted in the last 12 months or by non-empanelled agency; IT-OT boundary permeable — bidirectional unrestricted traffic.

11.8 Physical Security of Transmission Infrastructure

Physical security of transmission substations and tower lines is a material audit area given documented incidents of vandalism; theft of conductor and earthwire; and sabotage.

Substation Security: Perimeter fencing — condition; height; any breach; CCTV coverage — all entry points; critical equipment areas; transformer yards; control rooms; recording continuity;

storage period minimum 90 days; access control — biometric or card access for control room and high-voltage yard; visitor management register; security personnel — armed guard at designated critical substations; round-the-clock presence; coordination with local police.

Transmission Tower Lines: Tower line patrol — frequency; patrol records; vandalism reporting; theft of earth wire or conductor — immediate incident report; FIR filing; insurance claim; anti-climbing devices on towers — installed; condition; effectiveness. For remote transmission line sections — drone-based aerial surveillance; frequency; findings and follow-up.

Critical Substation Designation: Some substations are particularly critical — 765 kV or 400 kV substations feeding large cities; substation interconnecting regions; substations with no redundant supply path. Verify: critical substations identified; enhanced security measures applied; coordination with CISF or state police for armed protection; NCIIPC communication.

11.9 TRANSCO Financial Health Audit

While TRANSCOs have more predictable revenues than DISCOMs — ATC is approved and billed regardless of energy volumes, they still face specific financial risks that internal audit must address.

Receivables from DISCOMs: The primary credit risk for TRANSCOs is delayed payment of transmission charges by DISCOM beneficiaries. Many state DISCOMs are financially stressed — they delay transmission charge payments creating liquidity pressure on STUs. Verify: payment security — LCs; escrow in place as per TSA/PPA terms; aging analysis of transmission charge receivables; CERC complaint mechanism where payment security is breached; interest on delayed payment — computed and billed.

Working Capital Management: CERC/SERC allows working capital interest as a tariff component. Verify: actual working capital requirement vs normative working capital — any excess working capital borrowing not recoverable through tariff; interest rate on working capital borrowing — compare against SBI rate applicable for tariff; CERC normative working capital computation for verification.

Capital Expenditure Planning and CERC Admission: New transmission projects admitted for tariff only after CERC prudency check. Verify: ISTS schemes approved by the National Committee on Transmission (and, for regulated projects, CERC regulatory approval where required); intra-state schemes approved by the SERC in the capital investment plan; any expenditure without such approval — risk of non-admission; capital cost estimates — reasonable; not understated at DPR stage to obtain CERC approval then overrun during execution.

11.10 Fraud Risk Indicators — TRANSCO and LDC

Fraud Scheme	How It Works	Detection Procedure
Transmission tariff billing discrepancy	Excess ATC billed to beneficiaries above CERC-approved amount — additional billing pocketed through adjustment accounts	Reconcile monthly ATC billing with CERC/SERC approved ATC; verify beneficiary shares match the NLDC computation
Capital works contractor over-billing	Fictitious or inflated work certified in MB — quantities measured on paper not on ground	Physical measurement verification at substation and tower line sites; cross-check tower foundation dimensions with MB entries; drone survey of completed line sections

Fraud Scheme	How It Works	Detection Procedure
RoW compensation excess payment	Compensation paid at inflated rates to landowners; excess shared back with approving officials	Compare compensation rates against government notification rates; beneficiary verification; bank transfer records; district collector rate confirmation
SCED manipulation — false availability reporting	Generator reports higher available capacity to NLDC than actual — SCED produces sub-optimal solution disadvantaging competitors	SCADA generation data vs declared capacity cross-verification; NLDC SCED computation input vs actual performance
DSM settlement manipulation	DSM amounts in settlement records differ from RPC/RLDC settlement statements — difference siphoned	Independent reconciliation of DSM amounts with Grid-India settlement statements; bank credit verification
OT system insider threat — access abuse	Internal staff with OT access makes unauthorised changes to protection relay settings or SCADA configuration	User access log review for all OT systems; relay setting change log; SCADA configuration change log; any changes outside change management process
REC registry manipulation (NLDC)	Registry database records modified to issue extra RECs or revive cancelled RECs — sold for benefit	Registry audit trail analysis; cancelled REC ledger reconciliation; REC issuance vs SLDC-certified generation cross-check

12. DISCOM AUDIT

12.0 Introduction

Distribution companies are simultaneously the most financially stressed and the most operationally complex entities in India's power sector. They sit at the intersection of power purchase; regulatory compliance; consumer service; revenue recovery; and government subsidy management, each of which carries material audit risk. Despite handling tens of thousands of crores of annual revenue and serving hundreds of millions of consumers, DISCOMs have been the weakest link in India's power sector value chain for decades.

This chapter covers AT&C loss measurement and investigation; power purchase prudency; regulatory asset accounting; RDSS implementation; consumer protection compliance; financial health assessment; and smart meter-based data analytics.

Generic audit areas like procurement; stores; HR; treasury are covered in Chapter 14. This chapter focuses exclusively on what is unique to DISCOM audit.

12.1 Red Flag Dashboard — DISCOM

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
1	AT&C losses increasing year-on-year	Above 2 percentage point increase in any financial year	Revenue leakage acceleration; theft increase; metering failure
2	Collection efficiency below 90%	Below 90% in any quarter	Receivables crisis; DISCOM financial stress accelerating
3	Power purchase cost above tariff-order-approved level	More than 10% above tariff-order-approved power purchase cost	SERC prudency disallowance risk; merit order non-compliance
4	Regulatory asset growing without SERC approval	Any RA created without specific SERC order	Accounting irregularity; recoverability risk; Ind AS 114 non-compliance
5	ACS-ARR gap widening	Gap above Rs. 1 per unit and increasing year-on-year	Financial health deterioration; viability concern
6	RDSS milestone achievement below 50% of target	Smart meter rollout below 50% of annual target	Grant disbursement at risk; penalty by PFC or REC Limited (nodal agency) possible
7	RPO compliance below 80% of SERC annual target	RE purchase plus REC purchase below 80% of target	SERC penalty exposure; HPO non-compliance
8	CGRF complaint disposal below 70% within 45 days	Complaint disposal rate below 70% within 45-day statutory period	Electricity Ombudsman escalation; SERC notice
9	Government department dues outstanding beyond 6 months	Any government department account overdue beyond 6 months	Political risk; cash flow impact; write-off pressure
10	Short-term borrowing above 3 months revenue	Working capital loan outstanding above 3 months average revenue	Liquidity stress; PFC or REC Limited covenant risk; interest burden

12.2 AT&C Loss Audit

AT&C (Aggregate Technical and Commercial) loss is the single most important operational performance metric for a DISCOM. Every percentage point reduction in AT&C loss directly translates to revenue recovery. AT&C loss above SERC-approved norm results in tariff true-up disallowance — costs of excess losses cannot be recovered from consumers. Conversely, systematic under-reporting of AT&C loss inflates apparent performance and has been a documented fraud in DISCOM audit.

12.2.1 AT&C Loss Formula and Components

AT&C Loss% = [1 − (Units Billed × Collection Efficiency ÷ Input Units)] × 100

Where:

- ✓ Input Units = Energy received at all 33/11 kV substations from the transmission system at boundary metering points
- ✓ Units Billed = Units billed to all consumers in the billing period
- ✓ Collection Efficiency = Amount collected ÷ Amount billed

AT&C loss combines two distinct types of loss that must be tracked separately for root cause analysis: Technical losses — inherent in the physics of electricity distribution through lines and transformers; and Commercial losses — arising from theft; meter tampering; billing errors; and collection shortfall.

12.2.2 Input Energy Verification

Input energy is the denominator of the AT&C loss computation. Any under-recording of input energy inflates apparent AT&C performance. Any over-recording inflates apparent losses.

Audit Procedures: Boundary metering at each 33/11 kV substation — CEA (Installation and Operation of Meters) Regulations 2006 (as amended up to 2022) — meter accuracy class; calibration records; sealing; last testing date. Reconcile boundary meter readings with the TRANSCO/STU billing to the DISCOM — energy received per DISCOM's boundary meters should match energy billed by STU subject to metering accuracy tolerance. Any systematic difference — investigate.

Verify that all 33/11 kV substations are included in the input energy computation — no substation omitted from the monthly energy accounting. New substations commissioned during the year — included from commissioning date.

12.2.3 Distribution Loss Computation

DT-Level Energy Accounting: Where DT metering is available (a key RDSS target) — input at each distribution transformer minus sum of consumer units billed under that DT gives LT loss for that DT. DTs with very high LT loss indicate: local theft; meter tampering; agricultural unmetered consumers underestimated; faulty DT meter.

Feeder-level loss = Input at 11 kV feeder entry minus sum of DT inputs on that feeder = HT (High Tension) distribution loss on that feeder.

High-Loss Feeder Analysis: Rank all feeders by AT&C loss — identify top 10 loss feeders in each circle. These are priority areas for: anti-theft drives; meter testing; physical verification of consumer connections. Verify that management has a documented action plan for high-loss feeders and that internal audit tracks implementation of the plan.

Agricultural Consumer Energy Estimation: Most DISCOMs have significant proportions of unmetered agricultural consumers whose consumption is estimated based on connected load (HP) and assumed running hours per day and per year. This estimation basis is frequently outdated — pump installations have been replaced with higher-capacity pumps without updating DISCOM records; new connections not recorded; estimation assumes fewer running hours than actual in states with free power.

Verify: basis for energy estimation — when was the assumption last reviewed; is HP data current; are assumed running hours consistent with actual crop pattern and irrigation season; any field survey of pump installations in the last 3 years. Inflated estimation of agricultural consumption inflates units billed and appears to reduce AT&C loss — a common manipulation. The cross-check is: if AT&C loss is reported low but the DISCOM is financially stressed with high ACS-ARR gap — the estimation may be inflated.

12.2.4 Commercial Loss Investigation

Electricity Theft Detection: Section 126 governs assessment for unauthorised use of electricity, and Sections 135–140 govern theft and related offences, with civil liability for theft determined under Section 154(5). Verify: anti-theft drive records — number of inspections; number of theft cases detected; assessment raised under Section 126 (unauthorised use) or Section 135 (theft); FIR filed per Section 135 where warranted; assessment recovery tracking; amount recovered vs assessed.

Theft pattern analysis using smart meter data — smart meters generate alerts for: reverse current (meter bypassed); magnetic interference (magnet placed on meter to slow it); neutral disturbance (neutral wire tampered); communication loss (meter removed or communication blocked). Pull all tamper alerts from the Head End System; verify field investigation of each alert; confirmation of tamper; re-assessment of consumption; FIR where warranted.

Meter Accuracy and Testing: Defective meters systematically under-record consumption — contributing to commercial losses. Verify: meter testing programme — number of meters tested annually; percentage of total meters tested; percentage found defective; replacement rate; back-billing for defective period. CEA Metering Regulations prescribe periodic testing frequency — verify compliance.

Billing Accuracy: Random sample of consumer bills — verify: meter reading correctly transferred to bill; correct tariff category applied; correct rate per unit for the category; correct fixed charges; correct surcharges. Category misclassification — consumer billed at domestic rate but connection is commercial or industrial — results in revenue loss. Verify field verification of category for large commercial connections.

12.2.5 Collection Efficiency

Collection efficiency = Amount collected ÷ Amount billed. Compute category-wise — agricultural; domestic; commercial; industrial; government. Government department collection is frequently the weakest area in state DISCOM collection.

Aging Analysis: 0-30 days outstanding; 31-60 days; 61-90 days; 91-180 days; 181 days to 1 year; above 1 year — amount and number of accounts. High aging in commercial and industrial categories with significant arrears suggests: ineffective disconnection policy; political interference in disconnection; collusion between meter readers and consumers.

Government Department Dues: Government departments — hospitals; schools; water supply; municipalities; police; railways are frequently the largest individual debtors of state DISCOMs. Verify government department-wise outstanding amount; oldest dues; any formal demand raised; state government direction for payment; any set-off arrangements against DISCOM's own liabilities to the government.

Write-Offs: Any consumer accounts written off — Board approval; SERC implications; any write-off reversals — recovered amounts after write-off; correct accounting treatment.

12.2.6 Smart Meter Data Analytics for AT&C Loss

Smart meters generate data at 15-minute intervals enabling a quality of AT&C loss analysis that was impossible with electromechanical meters. The following analytics should be built into the internal audit data analytics programme:

Energy balance at HES (Head End System) level — total energy input at each DT (from DT meter) minus sum of all consumer smart meter readings under that DT minus technical losses assumed for DT and LT network = unaccounted energy. Where unaccounted energy is consistently high for a DT area — field investigation of possible new unauthorised connections; mass theft; meter communication failure etc.

Consumption anomalies — consumers showing sudden consumption drop after smart meter installation compared to estimated consumption before installation — indicates the old estimated consumption was inflated or the consumer was engaged in theft that the smart meter now prevents.

Zero consumption alerts — consumer account showing zero consumption for extended period (30 days or more) while meter is communicating — possible meter defect; consumer bypassing meter; or genuine zero consumption for empty premises. Field verification of zero consumption accounts monthly.

Tamper alert analysis — pull all tamper alerts from HES monthly; categorise by type; field investigation rate; conversion to detection and recovery; track false positive rate.

Night-time consumption analysis — consumers showing high consumption between 11pm and 5am compared to their category norm — possible unauthorised industrial activity in domestic premises; night shift activity not declared; irrigation pump misclassified as domestic.

Financial Impact Formula: AT&C loss revenue impact = (Actual AT&C loss% − SERC-approved AT&C loss%) ÷ 100 × Input energy MWh × Average realisation per MWh = Rs. revenue loss due to excess AT&C loss.

12.3 Power Purchase Audit

Power purchase is the largest expense of a DISCOM — typically 70-80% of total cost. SERC examines power purchase decisions for prudency during the tariff true-up — imprudent decisions result in disallowance of power purchase cost above the prudent amount, which cannot be recovered from consumers and must be absorbed by the DISCOM.

12.3.1 Merit Order Despatch Compliance

Merit order despatch means scheduling the cheapest available power source first and progressively more expensive sources as demand increases, thereby minimising total power purchase cost for any given level of demand. This is a regulatory obligation and a fiduciary duty of the DISCOM management.

Audit Procedures: Obtain the DISCOM's daily merit order — source-wise ranking by variable cost; scheduling of each source in merit order. Verify: actual despatch (scheduling instructions to LDC/SLDC) for a sample of days matches merit order; any out-of-merit-order scheduling — documented technical justification (must-run; technical minimum of thermal plant; grid constraint; force majeure).

SERC prudency audit approach — SERC during true-up compares: (a) the DISCOM's actual power purchase cost and (b) the cost that would have resulted from strict merit order despatch. Any excess of actual cost over merit order cost is presumed imprudent and disallowed unless DISCOM can provide specific justification for each out-of-merit decision. Internal audit should replicate this analysis as a pre-petition review — identify likely disallowances before the true-up petition is filed.

MERIT Portal Cross-Reference: The Ministry of Power's MERIT (Merit Order Despatch of Electricity for Rejuvenation of Income and Transparency) portal publishes state-wise, source-wise variable costs and merit order. Verify that the DISCOM's own merit order is consistent with MERIT portal data for the same period; any significant divergence — investigate.

12.3.2 Long-Term PPA Compliance

Audit Procedures: PPA terms — contracted capacity MW; tariff (capacity charge and energy charge); availability guarantee; backing-down provisions; payment timeline; payment security requirements as per PPA terms and MoP Standard Bid Document provisions.

Scheduled vs actual drawl — for each PPA-wise source; under-drawl from a cheaper source while over-drawing from a more expensive source is a merit order deviation; over-drawl beyond contracted capacity — settled under DSM. Capacity charges — payable even when power is not drawn if source is available; verify computation; any dispute with GENCO on availability declaration — cross-reference Section 8.3.2 on PAF from GENCO's side.

Backing-down compensation — where the DISCOM instructs the GENCO or RE developer to back down despite availability; deemed generation claim from RE developer must be verified and settled correctly; any unjustified backing-down of RE sources while purchasing more expensive conventional power — merit order and RPO compliance issue simultaneously.

12.3.3 Short-Term Power Purchase Prudency

Audit Procedures: Board-approved short-term power purchase policy — source limits; price ceiling; approved market segments; prior approval requirements above specified value; single-window vs Audit Committee approval. Emergency purchase — documented as emergency; technical necessity recorded; price premium justified; SERC approval obtained where required. Exchange purchase — DAM; RTM; G-DAM; TAM; settlement reconciliation with IEX/PXIL/HPX settlement advices; Board-approved trading policy compliance.

Price prudency pre-audit — for each significant short-term purchase; compare purchase price against prevailing market price at the same time as evidenced by exchange cleared price or trading platform data. Purchase significantly above prevailing market without documented justification — SERC disallowance risk; quantify exposure.

HP-DAM (High Price Day Ahead Market) purchases — Board approval mandatory; price above DAM ceiling; emergency documentation; SERC reporting where required by state SERC.

12.3.4 RPO and HPO Compliance

Audit Procedures: Obtain the RPO trajectory under the MoP Order of 22 July 2022 as adopted by the SERC, with its wind, hydro (HPO), distributed RE and other RE components. Actual RE purchase — from long-term RE PPAs; G-DAM; bilateral RE contracts; and RECs purchased for shortfall. Track each component monthly, including the HPO.

REC purchase for shortfall — where actual RE purchase falls short of RPO target; RECs can be purchased on IEX/PXIL/HPX to make up the shortfall; verify: REC purchases; RECs are eligible for the RPO component being met under the REC Regulations 2022 for the shortfall being covered; REC purchase cost is within Board-approved limit; accounting treatment.

RPO compliance certificate — filed annually with SERC; accuracy of data in certificate; timely filing; any SERC show cause for non-compliance; penalty computation.

Pre-Audit of RPO Position: RPO shortfall penalty exposure can be significant. Internal audit should compute the DISCOM's RPO compliance position quarterly — not annually. A quarterly alert allows management to take corrective action — procure additional RE or purchase RECs — before the year-end position is irretrievably non-compliant.

Financial Impact Formula: RPO shortfall penalty = SERC-prescribed penalty per unit shortfall × Shortfall units = Rs. penalty exposure. Or: shortfall units × prevailing REC market price = Rs. REC purchase required to achieve compliance.

12.4 Regulatory Asset Audit

Regulatory assets are one of the most material and most complex accounting areas unique to distribution utilities. Their incorrect treatment can materially misstate the DISCOM's financial position and mislead stakeholders about financial health.

12.4.1 What Is a Regulatory Asset

When a DISCOM's actual costs exceed the costs approved by SERC in the tariff order — and SERC permits the difference to be deferred for recovery in future tariff periods rather than being charged to consumers immediately — the deferred amount is recognised as a Regulatory Asset (RA) in the DISCOM's books under Ind AS 114 (Regulatory Deferral Accounts). The key principle is that SERC must specifically permit the deferral — a DISCOM cannot create a RA unilaterally.

The Electricity Rules (as amended) cap the revenue gap that may be created as a regulatory asset at 3% of ARR, to be liquidated within three years, and the Supreme Court in August 2025 directed regulators to clear existing regulatory assets within a fixed timeline. Verify compliance with both.

The risks associated with regulatory assets are: recoverability risk (SERC may refuse to allow recovery in future); time value risk (RA grows with carrying cost that may not be fully allowed); and disclosure risk (inadequate disclosure of RA balance and recovery mechanism misleads stakeholders).

The Delhi DISCOMs accumulated over Rs. 38,500 crore in regulatory assets over the years — illustrating how uncontrolled RA accumulation can threaten the financial viability of a DISCOM.

12.4.2 RA Creation — Audit Procedures

Step 1 — Verify SERC Order: Every RA must be supported by a specific SERC order permitting the deferral. Obtain: the specific SERC order; the amount permitted to be deferred; the period of

deferral; the nature of the cost being deferred (power purchase excess; O&M excess; subsidy shortfall). Any RA not supported by a specific SERC order is an impermissible deferral, a misstatement in the financial statements. Verify all RA balances against specific SERC orders authorising them.

Step 2 — Recoverability Assessment: A RA is an asset only if it is recoverable through future tariff surcharges. Assess: has SERC specifically committed to allowing recovery in a future tariff period? Has SERC specified the surcharge rate and recovery period? Is the DISCOM viable enough to survive until recovery is complete? If SERC has not committed to recovery — the RA may need to be impaired or written off. Ind AS 36 impairment assessment must be applied to RA balances where recoverability is uncertain.

Step 3 — RA Accounting Under Ind AS 114: Regulatory Deferral Account Balances — shown separately on the balance sheet as permitted by Ind AS 114 (an interim standard for rate-regulated entities). Carrying cost — interest accrued on RA balance at SERC-approved carrying cost rate; if SERC does not allow carrying cost, the time value loss is a financial cost that cannot be recovered. Disclosure — adequacy of notes explaining: nature of RA; SERC order basis; recovery mechanism; expected recovery period; any impairment.

Step 4 — RA Recovery Tracking: Where SERC has approved a surcharge for RA recovery — verify: correct surcharge rate applied in consumer billing; monthly surcharge collections; reconciliation of surcharge collected against RA balance reduction; any shortfall in surcharge collection tracked; SERC reporting of recovery progress.

12.5 RDSS Audit

The Revamped Distribution Sector Scheme (RDSS) launched in 2021 is the defining government initiative for DISCOM infrastructure upgradation. It provides performance-linked grants through PFC and REC Limited as nodal agencies. With a total outlay of about Rs. 3.04 lakh crore nationally, RDSS audit is a material area for every state DISCOM.

12.5.1 RDSS Grant Utilisation Audit

Sanction and Disbursement: Obtain RDSS sanction order — total sanction amount; component-wise (smart consumer meters; DT meters; feeder separation; 33/11 kV systems; IT/OT infrastructure); disbursement conditions — milestone-based; pre-qualifying conditions (DPR approval; baseline AT&C survey; financial health plan). Disbursement received to date — tranche-wise; conditions satisfied for each tranche.

Utilisation Certificate Accuracy: Utilisation Certificates (UCs) submitted to PFC or REC Limited (as the nodal agency) must be supported by actual physical achievement, not financial expenditure alone. Physical completion must precede UC submission. Verify: UC amounts match actual physical work completed; third-party verification of physical completion conducted; any UC submitted for work not completed — a serious irregularity warranting Audit Committee escalation.

Physical vs Financial Progress: Financial expenditure under RDSS vs physical targets achieved — fund utilisation percentage; physical completion percentage. Where funds are utilised significantly beyond physical completion — investigate: advance payments to contractors without corresponding work; diversion of funds; inflated contractor bills. Where physical completion significantly leads financial utilisation — verify correct accounting of expenditure.

12.5.2 Smart Consumer Meter Procurement Audit

Smart meter procurement under RDSS is one of the largest procurement exercises in DISCOM history — 250 million meters nationally. The procurement process and quality of meters procured are both material audit areas.

AMISP Procurement under TOTEX: Under RDSS, smart prepaid meters are deployed by an Advanced Metering Infrastructure Service Provider (AMISP) selected through competitive bidding on the MoP Standard Bidding Document, and paid a monthly charge per meter linked to service levels. Verify: bidding process and evaluation; contract terms against the SBD; monthly AMISP invoices against meters installed and communicating; SLA penalties deducted.

Technical Specification Compliance: Smart meters must meet IS 16444 (Indian Standard for Smart Meters); DLMS/COSEM communication protocol; required tamper detection features — reverse current; magnetic interference; neutral disturbance; communication loss; required accuracy class; remote connect/disconnect capability. Verify: meters procured carry BIS certification; factory acceptance testing records; sample testing at accredited laboratory.

Vendor Performance: Installation rate — meters supplied vs meters installed vs meters communicating. Meters installed but not communicating with HES are effectively non-functional. Verify: vendor's obligation to achieve communication (typically 95%+ communication rate within 30 days of installation); penalty for non-communication; actual communication rate from HES portal; vendor penalty invoked where applicable.

HES Cybersecurity: Head End System is the communication hub for all smart meters. HES cybersecurity — access controls; encryption of meter-HES communication; data integrity; tamper alert processing; server security. Refer Section 14.8.2 for detailed smart meter cybersecurity audit procedures.

12.5.3 DT Metering Audit

100% DT (Distribution Transformer) metering is a key RDSS target — it enables feeder-level and DT-level energy accounting which is the foundation of granular AT&C loss analysis.

Audit Procedures: DT meters installed vs total DTs — coverage percentage; unmetered DTs — reasons for gap (new DT; replaced DT; communication failure); DT meter accuracy — testing records; calibration; any systematic under-reading discovered from DT energy balance analysis.

Using DT meter data for energy accounting where DT metering data is available, the DISCOM should use it for monthly AT&C loss computation at DT level. Verify: DT data being used in energy accounting; any DTs excluded from energy accounting due to meter malfunction — estimated input used instead; basis of estimation.

12.5.4 AT&C Loss Target Compliance Under RDSS

RDSS conditions make grant disbursement conditional on achieving AT&C loss reduction milestones. Verify: RDSS AT&C loss trajectory for the DISCOM; actual AT&C loss for the current and previous year; compliance with RDSS milestone; any SERC-certified AT&C loss position required for RDSS tranche; accuracy of AT&C computation submitted for RDSS compliance.

12.6 Consumer Services Audit

The Electricity (Rights of Consumers) Rules 2020 (as amended up to 2024) create legally enforceable consumer protection standards that DISCOMs must comply with. Non-compliance

results in mandatory compensation to consumers; CGRF escalation; Electricity Ombudsman orders; and SERC action.

12.6.1 Standards of Performance

Standard	Prescribed Period (Maximum under Central Rules)	Audit Procedure
New connection — metropolitan area	3 working days from application	Sample check: application date vs connection date for 30 connections; compute average TAT; identify violations
New connection — other municipal area	7 working days from application	Same as above
New connection — rural area	15 working days from application	Same as above
New connection — hilly rural area	30 working days from application	Same as above
Supply restoration — urban	4 hours from reporting of outage	Outage records vs restoration records; average restoration time; violations above 4 hours
Supply restoration — rural	12 hours from reporting of outage	Same as above for rural supply points
Meter replacement after complaint	24 hours from complaint receipt	Complaint register vs replacement records; verify same-day or next-day completion
Billing complaint resolution	30 days from complaint receipt	Complaint register vs resolution date; complaints outstanding beyond 30 days
Compensation for SoP breach	Rs. 50-100 per breach as specified in SERC order	Verify SoP breaches identified; compensation paid to consumers without waiting for request

Note: The State Commission shall specify the maximum period, subject to the ceilings prescribed under Rule 4(11) of the Electricity (Rights of Consumers) Rules, 2020 (as amended up to 2024). Where extension of distribution mains or commissioning of a new substation is required, the period shall not exceed 90 days.

Compensation Payment Verification: Where SoP standards are breached, compensation must be paid to affected consumers automatically without the need of consumer to apply. Verify: mechanism for automatic identification of SoP breaches from system data; compensation billing or credit to consumer account; total compensation paid vs total breaches identified.

12.6.2 Consumer Grievance Redressal Forum (CGRF)

CGRF is mandatory under Section 42(5) of the Electricity Act 2003. Every DISCOM must constitute a CGRF for consumer grievance redressal.

Audit Procedures: CGRF constitution — composition; consumer representative; retired judge or senior officer of approved qualification; SERC approval of constitution; any changes in composition requiring fresh SERC approval. Meeting frequency — minimum monthly; verify meeting records;

quorum; any month without meeting — governance failure. Complaint disposal rate — percentage disposed within 45 days; complaints pending beyond 45 days — category-wise analysis; systemic issues causing delay. Compensation orders — compliance within 30 days of CGRF order; compensation paid to consumer; accounting entry. CGRF Annual Report — submitted to SERC by prescribed date; accuracy.

12.6.3 Electricity Ombudsman

The Electricity Ombudsman is appointed by SERC under Section 42(6) of the Electricity Act 2003 for redressal of consumer grievances not resolved by CGRF.

Audit Procedures: Ombudsman orders received during audit period — list; date; nature; amount awarded to consumer. Implementation within 30 days — mandatory; verify compliance for each order; any order not implemented within 30 days — non-compliance with Electricity Ombudsman is a serious matter; SERC can impose further penalty. Repeat orders from Ombudsman on the same DISCOM for similar issues — systemic failure indicator; root cause must be addressed.

12.6.4 DBT and Subsidy Audit

Electricity subsidies to domestic and agricultural consumers are a significant component of DISCOM revenue. Direct Benefit Transfer (DBT) for electricity subsidies is a state government initiative being implemented through Aadhaar-linked beneficiary databases in several states — direct credit of subsidy to beneficiary's bank account rather than subsidy paid to the DISCOM under Section 65 is being progressively implemented.

Beneficiary Database Integrity: Aadhaar seeding of all subsidised consumers — percentage seeded; un-seeded consumers (risk of ineligible persons in beneficiary list); deduplication — same Aadhaar linked to multiple consumer accounts; deceased consumers still receiving subsidy; consumers who have shifted but still receiving subsidy at old address.

DBT Disbursement: Subsidy amount credited to beneficiary's Aadhaar-linked bank account — per DISCOM billing cycle; verify: DBT amount computed correctly (subsidised units × subsidy rate per unit); credited to correct beneficiary account; MIS from state government DBT portal reconciled with DISCOM records.

State Government Reimbursement: The state government reimburses the DISCOM for subsidies given to eligible consumers. Reimbursement lag — time between subsidy given and state government reimbursement — creates working capital stress. Verify: subsidy claims raised on state government timely; reimbursement received; aging of outstanding reimbursement claims; any write-off or adjustment of subsidy claims — Board approval.

Category Misclassification: Consumers billed at subsidised domestic rate but using electricity for commercial or industrial purposes — revenue loss to DISCOM; also cross-subsidy distortion. Verify field verification programme for high-consumption domestic accounts; reclassification process; back-billing for misclassification period.

12.7 DISCOM Financial Health Audit

12.7.1 ACS-ARR Gap Analysis

The ACS-ARR gap is the primary indicator of DISCOM financial health and the basis for assessing long-term viability.

ACS (Average Cost of Supply): Total cost incurred by DISCOM for procuring and distributing electricity ÷ total units sold (kWh) = Rs. per kWh.

ARR (Average Revenue Realised — as used in the ACS–ARR gap): Total revenue collected from all consumers ÷ Total units sold = Rs. per kWh.

Gap = ACS − ARR. Positive gap means DISCOM loses money on every unit sold. Subsidy dependence — proportion of gap covered by state government subsidy; if subsidy covers the full gap, the DISCOM is operationally viable but financially dependent on the state.

Trend Analysis: Three-year trend of ACS; ARR; and gap — is the gap narrowing (improvement in tariff revision and/or AT&C loss reduction) or widening (tariff revision lagging; AT&C losses increasing)? Component analysis of ACS — power purchase cost per unit; transmission cost per unit; O&M cost per unit; depreciation per unit; interest per unit — which component is driving ACS increase?

Financial Impact of ACS-ARR Gap: Annual financial loss = (ACS − ARR) × Total units sold. If this exceeds the annual grant or state government subsidy — cumulative losses are increasing. Trend of accumulated losses on balance sheet — sustainability assessment.

12.7.2 Working Capital and Liquidity

Power Purchase Payables: Power purchase payables to GENCOs — aging analysis: 0-30 days; 31-45 days; 46-60 days; above 60 days. Late Payment Surcharge (LPS) — under the Electricity (Late Payment Surcharge and Related Matters) Rules 2022, amounts unpaid after the due date (45 days from presentation of the bill, or as specified in the PPA) attract LPS at the base rate (SBI one-year MCLR plus 5%) for the first month, increasing by 0.5% for each subsequent month up to a maximum of 3% above the base rate. Compute LPS on each overdue bill accordingly. Verify: LPS has been accrued in the books; any LPS demand from GENCOs — response filed; settlement.

Payment security mechanism — PPA terms and MoP Standard Bid Documents require adequate payment security (LC/escrow). Verify: LC opened for each PPA; LC amount as required under the PPA and the LPS Rules 2022; any breach of payment security — invoke PPA remedies; adjudication by the SERC under Section 86(1)(f) (or CERC under Section 79(1)(f)).

Short-Term Borrowing: Working capital loans outstanding — lender-wise; interest rate; maturity; any loan covenant conditions. Compare outstanding loan amount against 3 months average revenue — ratio above 1 indicates excessive short-term borrowing. Interest cost on short-term borrowing — allowed in SERC tariff order computation; actual vs normative interest rate.

Cash and Bank Balance: Minimum cash balance for operational continuity — adequacy; any period of cash shortfall; overdraft utilisation.

12.7.3 PFC and REC Loan Covenant Compliance

Where DISCOM has borrowed from PFC or REC under RDSS or legacy schemes:

DSRA — verify required balance as per loan agreement; actual balance from bank statement; any shortfall — lender notification.

Performance covenants — PFC and REC Limited loans under RDSS carry performance conditions: AT&C loss trajectory; metering targets; financial ratios. Verify compliance with each covenant; any breach — reported to lender; waiver obtained.

Utilisation Certificate compliance — RDSS grant UCs must be submitted to PFC or REC Limited (as the nodal agency) on time; accuracy; physical verification supporting UC.

Financial covenants — DSCR where applicable; if DSCR falls below covenant level — lender notification; waiver request.

12.8 Open Access and Franchisee Audit

12.8.1 Open Access Consumer Audit

HT consumers above the notified threshold have the right to purchase power from sources other than the DISCOM through open access. Under the Green Energy Open Access Rules 2022, consumers with contracted demand of 100 kW and above may procure green power through open access. DISCOMs charge cross-subsidy surcharge and wheeling charges on open access consumers.

Audit Procedures: Open access consumers — list of all consumers using intra-state or inter-state open access; contracted capacity; source of power; SLDC scheduling compliance. Cross-subsidy surcharge — computation per SERC-notified rate; billing; recovery; any exemptions claimed (captive plants — 26% ownership + 51% consumption rule — verify eligibility). Wheeling charges — computation per SERC notification; billing; recovery; additional surcharge where applicable.

Any under-recovery of cross-subsidy surcharge or wheeling charges from open access consumers — quantify; SERC reporting; recovery action.

12.8.2 Distribution Franchisee Audit

Where the DISCOM has appointed distribution franchisees for specific geographic areas:

Franchise agreement compliance — revenue guarantee; AT&C loss target; consumer service standards; investment obligations. Revenue from franchisee area — collection by franchisee; remittance to DISCOM; timing; shortfall. DISCOM's oversight of franchisee — regular review meetings; performance against benchmarks; termination provisions where performance is below contracted level. Consumer complaints from franchisee area — CGRF jurisdiction; Ombudsman applicability. Any anti-competitive behaviour by franchisee — SERC reporting.

12.9 EV Charging, Net Metering and Prosumer Audit

12.9.1 EV Charging Infrastructure Audit

Audit Procedures: SERC EV tariff — applicable category for EV charging stations; correct tariff applied in billing; any EV charging station billed at incorrect (lower) tariff — revenue loss. EV charging station metering — BIS-certified meter; accuracy class; data communication to DISCOM billing system. Demand response arrangements — interruptible load contracts with large EV fleet operators (bus depots; ride-share aggregators); verify terms; activation records; revenue from demand response.

Revenue from EV charging as a separate revenue stream — correctly classified in financial statements; asset capitalisation of EV charging infrastructure where owned by DISCOM.

12.9.2 Net Metering and Prosumer Audit

Net metering allows consumers with rooftop solar to export surplus generation to the DISCOM's grid and receive credit for exported units.

Audit Procedures: Net metering policy — SERC order; eligible capacity limit (typically up to 500 kW for net metering; above this — gross metering); application process; connection timelines.

Bidirectional meter installation — verify consumer has bidirectional meter; meter is BIS-certified; meter sealed; tariff category updated to prosumer. Net energy settlement — import units (consumed from grid) minus export units (exported to grid) = net units billed at retail tariff; where export exceeds import — credit in consumer's account; banking of excess credits; settlement at year-end.

PM Surya Ghar Muft Bijli Yojana compliance — rooftop solar target; subsidy disbursement to eligible beneficiaries (up to Rs. 78,000 per household); Aadhaar-linked beneficiary verification; net meter installation within 30 days of solar installation; vendor empanelment process; any fraud in PM Surya Ghar subsidy claims — verify beneficiary actually installed solar.

12.10 Fraud Risk Indicators — DISCOM

Fraud Scheme	How It Works	Detection Procedure
AT&C loss understatement — agricultural estimate inflation	Agricultural consumption estimate inflated — units billed inflated — AT&C loss appears lower; RDSS milestones appear met without actual improvement	Independent field survey of agricultural pump HP and running hours; energy balance cross-check; compare estimated consumption with adjacent well-metered feeder consumption
Meter tampering by consumers with meter reader collusion	Consumer bypasses meter; meter reader records normal reading in exchange for consideration	Smart meter tamper alert analysis; compare consumption pre- and post-smart meter installation for same consumer; biometric attendance for meter readers on route
Cash collection not deposited — cashier fraud	Consumer pays cash; cashier issues receipt but does not deposit full amount in bank	Daily cash collection vs bank deposit slip reconciliation; surprise cash count at collection centres; compare physical receipt book vs system entry
Billing parameter manipulation	Meter reading correctly entered but tariff category downgraded in billing system — consumer billed at lower rate	System audit of tariff category changes in billing software; who has authority to change category; audit trail review; field verification of category for changed accounts
False disconnection — ghost connection	Consumer disconnected in DISCOM records but connection physically alive — consumer continues to consume without billing	Field verification of physically disconnected connections; meter seal intact vs system disconnection record; any reconnection charges collected but disconnection not done
Power purchase manipulation — merit order bypass	DISCOM purchases from expensive source while cheaper source is available — supplier pays consideration to decision-maker	Merit order analysis; price comparison at time of each short-term purchase; bank statement of trading desk officers
Government department dues suppression	Government department dues not shown in aging report — written off informally or adjusted against dues from government	Government department-wise aging independent from billing system; direct confirmation from government department of outstanding amount

Fraud Scheme	How It Works	Detection Procedure
RDSS UC inflation	Utilisation certificates submitted to PFC or REC Limited for work not completed — additional tranche released	Physical verification of work claimed in UC; third-party inspection records; contractor bill dates vs UC submission date
PM Surya Ghar subsidy fraud	Subsidy claimed for rooftop solar not installed — beneficiary colludes with installer	Field inspection of beneficiary premises; photographic evidence of installation; meter reading showing generation

13. ENERGY EXCHANGE AND CARBON MARKET AUDIT

13.0 Introduction

Energy exchanges and carbon markets represent the most rapidly evolving segment of India's power sector from an audit perspective. The Indian Energy Exchange (IEX), Power Exchange India Limited (PXIL) and Hindustan Power Exchange (HPX) are the three CERC-licensed power exchanges, together handling several hundred billion units of electricity a year. The Carbon Credit Trading Scheme (CCTS) established under the Energy Conservation (Amendment) Act 2022 is creating a domestic carbon market that will have material compliance obligations for large power sector entities. The PAT (Perform Achieve and Trade) Scheme under the Bureau of Energy Efficiency has been running for several cycles and generates ESCerts that are traded on exchanges.

This chapter covers three interconnected audit areas: power exchange participation and settlement audit; REC trading compliance audit; and carbon market audit covering CCTS; ESCert; and international carbon credits under Article 6 of the Paris Agreement.

Section 10.6 covers REC registration and issuance audit from the RE GENCO's perspective. This chapter covers what happens after RECs are issued like trading on exchanges; settlement; accounting; and compliance.

Section 12.3.4 covers RPO compliance from the DISCOM's perspective including REC purchase. This chapter covers the exchange platform audit applicable to all participants.

A key distinction for this chapter: the internal auditor is not auditing the exchange itself (IEX, PXIL and HPX are regulated by CERC — IEX, as a listed company, is also subject to SEBI — and have their own internal audit frameworks). The internal auditor is auditing a power sector entity like GENCO; DISCOM; or trader that participates in the exchange as a member. The audit focus is therefore on the member entity's compliance; settlement reconciliation; policy adherence; and financial accounting.

13.1 Red Flag Dashboard — Energy Exchange and Carbon Market

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
1	Exchange trading policy absent or not updated	No Board-approved trading policy or policy not reviewed in 2 years	All exchange purchases or sales lack governance basis; prudency disallowance risk
2	DAM settlement unreconciled beyond 15 days	Monthly DAM settlement advices not reconciled within 15 days	Revenue leakage; counter-party dispute undetected
3	Position limit breached on any session	Any session where traded volume exceeds CERC-approved position limit	CERC regulatory violation; exchange penalty; member suspension risk
4	REC inventory not traded beyond 6 months	RECs held in inventory for more than 6 months without trading strategy	REC value at risk; impairment may be required
5	ESCert deficit at year end of PAT cycle	Net ESCert position negative at PAT cycle end	BEE penalty — Rs. per unit of shortfall; significant financial liability

#	Red Flag Indicator	Threshold (Indicative)	Implication if Breached
6	GHG inventory not prepared for current year	CCTS obligated entity has not prepared GHG inventory for the assessment year	CCTS non-compliance; National Carbon Registry default
7	Carbon credit MRV plan not implemented	MRV plan exists but verification activities not conducted	Carbon credit issuance at risk; accredited verifier finding
8	HP-DAM purchase without Board approval	Any HP-DAM purchase above approved threshold without Board approval	DFP violation; SERC prudency disallowance
9	Collateral margin not reconciled	Exchange margin deposits not reconciled with exchange statements for 2 months	Asset misstatement; excess margin not reclaimed
10	Article 6 credit transfer not documented	Cross-border carbon credit transfer without bilateral agreement documentation	FEMA compliance risk; carbon credit accounting misstatement

13.2 Power Exchange Participation Audit

13.2.1 Trading Policy Governance

A Board-approved trading policy is the governance foundation for all exchange participation. Without a policy, every trading decision lacks organisational sanction and every purchase or sale is potentially challengeable as unauthorised.

Audit Procedures: Verify existence of Board-approved trading policy — Board resolution approving the policy; date of approval; date of last review (should be reviewed annually or when significant market changes occur). Policy content verification — must cover: which market segments are permitted (DAM; RTM; TAM; G-DAM; HP-DAM; derivatives); price ceiling for purchases and price floor for sales in each segment; maximum volume per trading session; maximum cumulative open position; approved counter-parties for bilateral trades; escalation matrix — who approves above what threshold; hedging policy — permitted instruments; hedge ratio limits; Ind AS 109 designation requirements.

Policy compliance verification — pull all trading transactions for the audit period; verify each transaction falls within policy parameters. Any transaction outside policy parameters — DFP violation; escalate to Audit Committee.

13.2.2 Member Registration and Compliance

Audit Procedures: Exchange membership validity — current registration; any suspension or warning notices from IEX/PXIL/HPX; annual membership renewal; CERC registration as market participant — valid; any CERC notice for violation. Know Your Customer (KYC) — member KYC documents current; any change in ownership or management requiring fresh KYC. Portfolio manager — designated and CERC-registered; authority letter; changes in portfolio manager notified to exchange.

Position limits — CERC approves position limits for each member in each market segment. Verify: current approved position limits; daily trading volume vs position limits; any breach in the audit period — CERC reporting of breach; exchange penalty; corrective action.

13.2.3 Collateral and Margin Management

Power exchanges require members to deposit collateral (cash or bank guarantee) as margin to support their trading positions. Unclaimed excess margin is a financial leakage; inadequate margin can cause trading to be suspended.

Audit Procedures: Margin deposit — total collateral deposited with IEX, PXIL and HPX; composition — cash; fixed deposit; bank guarantee; verify all bank guarantees are valid and renewed before expiry. Daily margin call tracking — was margin call received; was it met within the prescribed time; any instance of trading suspended due to inadequate margin — investigate cause.

Monthly margin reconciliation — statement from exchange showing margin deposited vs margin utilised; balance available; verify reconciliation with books; any discrepancy — investigate and recover. Excess margin — where trading volume has reduced, excess margin may be lying with the exchange earning no return; identify and reclaim excess margin; invest in approved instruments.

Collateral returns — when collateral is returned by exchange; accounting entry; bank credit verification; FD maturity on BG returns — verify FD released or BG returned.

13.3 Day Ahead Market (DAM) Audit

13.3.1 DAM Overview and Audit Relevance

The Day Ahead Market is the most liquid segment of Indian power exchanges — electricity for delivery on the following day is traded through a double-sided closed auction for each 15-minute time block. For DISCOMs, the DAM is the primary platform for balancing shortfalls in long-term PPA coverage. For GENCOs with merchant capacity, the DAM is the primary revenue source.

13.3.2 DAM Purchase Audit (DISCOM perspective)

Audit Procedures:

Step 1 — Purchase Necessity: Each DAM purchase represents a decision that long-term PPA supply is insufficient for that day. Verify: demand forecast for the day vs long-term PPA availability for that day; gap computation; DAM purchase volume consistent with the gap; no DAM purchase when long-term PPA was available and not scheduled — merit order violation.

Step 2 — Price Prudency: DAM clearing price for each time block is the market-cleared price — the same for all buyers. Prudency question is not on price (market determines it) but on whether the purchase decision was made and whether the DISCOM could have obtained the energy cheaper elsewhere at the time. Verify: was there a cheaper alternative available — RTM; bilateral; trader; unused LT PPA capacity — that was not used; documentation for any decision to use DAM rather than cheaper source.

Step 3 — Settlement Reconciliation: IEX/PXIL/HPX settlement statement — daily; showing: volume purchased per time block; clearing price per time block; total settlement amount; netting with any sales in same session. Reconcile settlement statement with: bank debit for settlement payment (settlement T+1 or as prescribed); books of accounts — power purchase cost entry; correct ledger and cost centre.

Monthly reconciliation — total DAM purchases per exchange settlement vs total booked in power purchase accounts; any discrepancy — investigate; common causes include: bank transfer delay; settlement date vs accounting date mismatch; rejected bids accounted as purchases.

13.3.3 DAM Sale Audit (GENCO/Merchant perspective)

Audit Procedures: Sale decision — Board trading policy compliance; price floor not breached; volume within position limits. Settlement — exchange settlement statement; bank credit for net settlement receivable; reconciliation with revenue books. Revenue recognition — Ind AS 115 — performance obligation (delivery of electricity in the contracted time block) satisfied on delivery; revenue recognised on settlement date or delivery date per accounting policy; consistency.

13.4 Real Time Market (RTM) and Term Ahead Market (TAM) Audit

13.4.1 RTM Audit

The Real Time Market was launched in June 2020 for trading electricity in 15-minute time blocks with gate closure one hour before delivery. It serves as a last-resort balancing mechanism.

Specific Audit Points for RTM: RTM purchases are typically emergency balancing transactions — higher price than DAM is expected and acceptable given the last-minute nature. Verify: RTM is used for genuine last-minute balancing needs only; not used as primary procurement channel in place of cheaper DAM or long-term PPA; frequency of RTM purchases — high frequency suggests poor demand forecasting or long-term PPA insufficiency; RTM price vs prevailing DAM price at the same hour — premium paid; documented justification.

RTM settlement — same T+1 settlement as DAM; reconciliation with books; bank debit verification.

13.4.2 TAM Audit

The Term Ahead Market (TAM) covers power-exchange contracts for physical delivery of electricity on T+2 or later, including daily, weekly, monthly and other longer-duration contracts as approved by CERC from time to time.

Specific Audit Points for TAM: TAM is useful for planned procurement where demand is more foreseeable. Board trading policy — TAM contracts require Board approval above specified thresholds given their longer duration. Weekly and monthly contracts — volume committed; price locked; delivery performance. Settlement — TAM settlement follows different settlement cycle from DAM/RTM; verify settlement statements; bank debits/credits; books.

Accounting — TAM contracts are physically settled and normally qualify for the own-use exemption from Ind AS 109; verify the documented basis, and apply mark-to-market only where a contract does not qualify.

13.5 Green Day Ahead Market (G-DAM) and HP-DAM Audit

13.5.1 G-DAM Audit

The Green Day Ahead Market launched in 2021 provides a separate market segment for RE-attributed power — electricity certified as generated from renewable sources.

For RE GENCOs selling in G-DAM: RE certification — only generators with certified RE capacity can sell in G-DAM; verify that units sold in G-DAM come from RE generation only; not from fossil fuel backup; metering supports the RE attribution. Settlement and revenue — G-DAM clearing price; settlement; bank credit; revenue recognition. REC interaction — where a GENCO sells in G-DAM as RE-attributed power; those units may not simultaneously qualify for REC

issuance (double-counting risk); verify with NLDC REC registry — no units appearing in both G-DAM RE-attributed sale and REC application.

For DISCOMs purchasing in G-DAM: G-DAM purchases count toward RPO compliance — verify RPO accounting accurately reflects G-DAM purchases by technology; accounting in books as separate category from conventional power purchase; cost per unit benchmarked against RPO compliance cost alternative (REC purchase).

13.5.2 HP-DAM Audit

The High Price Day Ahead Market was introduced for periods of high demand and supply scarcity as it has a higher price ceiling than regular DAM.

Specific Audit Points: Board approval — HP-DAM purchases above a Board-specified threshold require specific Board approval given the premium price. Verify: Board approval obtained before each HP-DAM purchase above threshold; any purchase without approval — DFP violation. Emergency documentation — HP-DAM should only be used in genuine supply emergency; document the emergency on record before purchase. SERC reporting — some SERCs require post-facto reporting of HP-DAM purchases; verify compliance.

Financial impact assessment — HP-DAM price premium over DAM price × quantity purchased = premium paid in excess of DAM alternative. Whether this is prudent depends on whether DAM had available supply at the time; document the market conditions.

13.6 Electricity Derivatives Audit

Electricity futures are traded on commodity exchanges (MCX and NSE, launched in July 2025) under SEBI regulation and are cash-settled against the power exchange day-ahead price; power exchanges offer physically delivered forward contracts under CERC regulation. Both can be used to hedge price risk.

Audit Procedures: Board-approved hedging policy — is there a policy specifically authorising use of electricity derivatives? Position limits for derivatives — separate from physical power limits; verify the position limits set by the commodity exchange under SEBI rules; any breach.

Hedge designation under Ind AS 109 — where derivatives are used for hedging price risk on forecast electricity purchases or sales; formal hedge designation required at inception: identification of hedging instrument (the derivative); hedged item (the forecast purchase or sale); hedging relationship (cash flow hedge); effectiveness assessment — retrospective and prospective. Any derivatives not designated as hedges — mark-to-market through P&L; volatility in reported earnings.

Settlement — derivatives settlement is financial (cash settled against the exchange index price); not physical delivery; settlement reconciliation with books; bank statement verification.

Speculative derivatives — any derivatives entered beyond the hedge requirement — trading desk activity unsanctioned by Board policy — constitutes speculation; must be reported to Audit Committee; marked-to-market immediately.

13.7 REC Trading Audit

Section 10.6 covers REC registration and issuance from the RE GENCO's perspective. This section covers REC trading compliance which is applicable to both RE GENCOs selling RECs and

obligated entities (DISCOMs; open access consumers; captive plants) buying RECs for RPO compliance.

13.7.1 REC Trading Compliance

For RE GENCOs selling RECs: Trading strategy — verify Board-approved strategy covering timing, volume and holding of RECs. Position in the Central Agency registry — total RECs held, vintage and validity, as applicable. Verify REC transactions through power exchanges/electricity traders — volumes sold and prices achieved against the applicable session clearing/transaction price.

Settlement reconciliation — reconcile exchange/trader settlement statements and bank credits with revenue recognised in the books; investigate discrepancies.

Inventory management — review ageing of unsold RECs, trading strategy and appropriate accounting/valuation treatment in accordance with the applicable accounting policy and Accounting Standards/Ind AS.

For DISCOMs and obligated entities buying RECs: Compute the RPO shortfall by component and verify that the RECs purchased are eligible for meeting the applicable RPO obligation under the prevailing CERC REC Regulations, Ministry of Power framework and the relevant SERC regulations/orders. Verify REC quantities purchased against the compliance requirement and examine excess/shortfall and permitted carry-forward/banking, where applicable.

Settlement reconciliation — reconcile REC purchase/settlement statements and bank debits with accounting records and verify appropriate classification of REC/RPO compliance cost.

13.7.2 REC Accounting Treatment

REC accounting has been a source of inconsistency across power sector entities. The correct treatment under Ind AS:

RECs held for sale (by RE GENCO) — classified as inventory (Ind AS 2) where they are generated in the ordinary course of business and held for sale; or as intangible assets (Ind AS 38) where they are not inventory in nature; accounting policy must be disclosed and applied consistently.

RECs purchased for RPO compliance (by a DISCOM) — recognised at cost as an asset (inventory or intangible, per the disclosed policy) until surrendered for compliance, and then expensed as RPO compliance cost in the period to which the compliance relates.

Revenue from REC sale (RE GENCO) — Ind AS 115; performance obligation is transfer of the REC to the buyer; recognised on settlement; not on issuance or on trading order placement.

Verify consistency of accounting policy across years; appropriate disclosure in financial statements.

13.8 ESCert Trading — PAT Scheme Audit

13.8.1 PAT Scheme Overview

The Perform, Achieve and Trade (PAT) Scheme under the Energy Conservation Act, 2001 prescribes energy-performance targets for notified Designated Consumers (DCs). Thermal power plants meeting the prescribed energy-consumption threshold are covered as DCs. DCs achieving energy performance better than the notified target may be entitled to Energy Savings Certificates (ESCerts), while those falling short are required to meet the prescribed compliance obligation, including through purchase of ESCerts, as applicable.

PAT operates through notified cycles, generally covering three-year periods. PAT Cycle VII covers FY 2022-23 to FY 2024-25, while PAT Cycle VIII covers FY 2023-24 to FY 2025-26 for the DCs/sectors notified thereunder. As PAT cycles may overlap, the applicable cycle, target and assessment period should be verified from the notification applicable to the individual DC.

13.8.2 Audit Procedures — PAT Compliance

Step 1 — Designated Consumer Registration: Verify entity is registered with BEE as a Designated Consumer; registration certificate; correct sector (thermal power); SEC baseline correctly established; any change in installed capacity or production process that affects the baseline — BEE approved revision.

Step 2 — Net Heat Rate Computation: For thermal power stations, BEE expresses the PAT energy-consumption norm/target and achievement as Net Heat Rate (kcal/kWh), computed and normalised in accordance with the prescribed BEE methodology. Verify gross heat rate, auxiliary power consumption, net generation and all applicable normalisation factors against source records and the BEE methodology.

Step 3 — Measurement and Verification (M&V): BEE requires an accredited M&V agency to verify the SEC achievement at the end of each PAT cycle. Verify: M&V agency is BEE-accredited; engagement letter; M&V report issued; BEE acceptance of M&V report; any BEE observations on M&V findings — compliance.

Step 4 — ESCert Position: Surplus ESCerts — if actual SEC is below (better than) SEC target: surplus ESCerts issued by BEE per M&V verification; ESCerts credited to entity's account on BEE's electronic portal. Deficit position — if actual SEC is above (worse than) target: ESCerts must be purchased to cover the deficit before the compliance deadline; BEE penalty for uncovered deficit.

Step 5 — ESCert Trading: Surplus ESCert holders sell on IEX/PXIL/HPX; deficit entities purchase. Exchange trading settlement — same as other exchange instruments; settlement reconciliation with books.

Accounting treatment: ESCerts held (surplus) — intangible asset or inventory depending on accounting policy; NRV assessment. ESCert purchase for compliance — compliance cost; recognised when used for compliance. Revenue from ESCert sale — Ind AS 115 — on transfer.

Step 6 — BEE Penalty Computation: Where entity has a net deficit position at cycle end — BEE penalty is prescribed per unit of energy shortfall. Verify: deficit position accurately computed; BEE penalty demand received; provision in books; any appeal filed — basis; likely outcome; contingent liability disclosure.

Financial Impact Formula: BEE PAT penalty = ESCert deficit units × BEE-prescribed penalty rate per unit = Rs. penalty liability.

13.9 Carbon Credit Trading Scheme (CCTS) Audit

13.9.1 CCTS Framework

The Carbon Credit Trading Scheme 2023 notified by the Ministry of Power vide S.O. 2825(E) dated 28 June 2023 under Section 14AA of the Energy Conservation (Amendment) Act 2022 establishes India's domestic carbon market — the first mandatory domestic carbon market in India. BEE is the administrator. The National Carbon Registry (NCR) is the registry for issuance, holding and surrender of Carbon Credit Certificates. CERC notified the CERC (Terms and Conditions for

Purchase and Sale of Carbon Credit Certificates) Regulations 2026 on 27 February 2026 providing the detailed trading framework for Carbon Credit Certificates on power exchanges.

The CCTS has two mechanisms: a compliance mechanism, under which entities in notified sectors are obligated to meet GHG emission intensity targets (targets for the power sector are yet to be notified); and an offset mechanism, under which entities may voluntarily register projects to generate and trade carbon credits.

As of the date of this publication, BEE is in the process of finalising sector-specific emission intensity targets for the power sector. Internal auditors should monitor BEE notifications for the power sector CCTS targets — once notified, obligated entities will have mandatory compliance obligations with significant financial implications. Refer Section 4.5.1.

13.9.2 GHG Inventory Audit

Applicable standard: GHG Protocol Corporate Accounting and Reporting Standard; IPCC emission factors; CEA CO_2 Baseline Database; BEE's detailed procedures and MRV guidelines under CCTS.

Step 1 — Activity Data Accuracy: GHG inventory is built from activity data — fuel consumption; electricity purchased; process inputs. For a thermal power plant:

Scope 1 emissions (direct) — primary source is fuel combustion in boilers. Activity data = coal consumed in tonnes; GCV of coal in Kcal/kg; emission factor for coal in kg CO_2e per Kcal. Verify: coal consumption data reconciles with fuel management records from Chapter 8; GCV used in the GHG inventory is the as-fired GCV, consistent with the SHR computation (Section 8.3.3); any unexplained difference is a data integrity red flag. Emission factor — IPCC Tier 1 or Tier 2 factors; or from the CEA CO_2 Baseline Database; documented source; consistent year-on-year.

Scope 2 emissions (indirect — purchased electricity) — auxiliary power from grid during plant start-up or outage. CEA grid emission factor applicable to the region.

Scope 3 emissions (value chain) — currently voluntary in India under BRSR Leadership Indicators; include coal mining operations (if integrated GENCO); employee commuting; transmission losses. Verify: Scope 3 boundary clearly defined; methodology documented; consistent year-on-year.

Step 2 — Emission Factor Verification: Emission factors — source documented; appropriate for the fuel type and technology; any change in emission factor from prior year — reason documented; impact on comparability disclosed.

Step 3 — Calculation Accuracy: GHG emissions (tCO_2e) = Activity data × Emission factor × Global Warming Potential (GWP) for the gas. CO_2: GWP = 1; CH_4: GWP = 25 (AR4) or 28 (AR5); N_2O: GWP = 298 (AR4) or 265 (AR5) — the GWP set used must be documented and applied consistently (CCTS and Paris Agreement reporting use AR5). Verify calculation for each emission source; total Scope 1 and Scope 2 emissions.

13.9.3 MRV Plan Compliance

Monitoring; Reporting; and Verification (MRV) is the process by which GHG emissions are quantified; reported; and independently verified to a level of accuracy that supports carbon credit issuance or compliance assessment.

Audit Procedures: MRV plan — obtain entity's MRV plan; verify it is consistent with BEE/NCR guidelines; monitoring parameters identified; monitoring frequency; data collection procedure; quality control; reporting template.

Monitoring implementation — are the monitoring activities actually being conducted? Verify: calibration of flow meters; GCV analysers; electricity meters used for GHG inventory; data recording — electronic; tamper-resistant; accessible to verifier. Any monitoring gap — period where data was not collected; how was the gap handled (estimation; conservative default — prescribed by MRV guidelines).

Reporting — GHG inventory report prepared and submitted to NCR on time; format per NCR template; completeness.

13.9.4 National Carbon Registry Operations

NCR Registration: Verify entity is registered on NCR — registration certificate; account credentials; authorised signatories.

Carbon Credit Issuance: After successful VVB verification — carbon credits are issued by NCR to the entity's registry account. Verify: credits issued match verified emission reductions; no duplication from same project period. Credit vintage — year of emission reduction; CCTS may have vintage rules (credits from too many years ago may not be used for compliance).

Carbon Credit Accounting: Carbon credits generated — asset in books; what classification? Intangible asset (Ind AS 38) or government grant (Ind AS 20 — if received for free) depending on the CCTS structure. If credits are issued as a result of verified emission reductions that the entity achieved through its own operational changes — they are likely an intangible asset at nil cost (since the emission reduction was achieved as part of normal operations without incremental cost); selling price on trading = revenue from Ind AS 115. If compliance credits are purchased by an obligated entity — cost of compliance; expense when surrendered.

Carrying value — NRV or fair value assessment where credits are held as assets and market prices are observable from power exchange clearing prices.

Carbon Credit Trading: On power exchanges under the CERC CCC Regulations — prices; settlement; bank credit; revenue recognition. Any restriction on transfer — lock-in period; vintage rules; ensure transfers comply with CCTS Regulations.

13.10 International Carbon Markets — Article 6 Audit

13.10.1 Article 6 Framework

Article 6 of the Paris Agreement enables countries to transfer carbon credits internationally through bilateral agreements — Internationally Transferred Mitigation Outcomes (ITMOs). India has begun entering into bilateral arrangements for ITMO transfers, starting with the Joint Crediting Mechanism with Japan. Projects in the activities notified by the Government as eligible for Article 6 (such as RE with storage, green hydrogen and offshore wind) may generate credits for international transfer, with a corresponding adjustment to India's NDC.

13.10.2 Audit Procedures — Article 6 Credits

Letter of Authorisation: An entity seeking to generate Article 6 credits must obtain a Letter of Authorisation from the National Designated Authority for the Implementation of the Paris

Agreement (NDAIAPA) under MoEFCC. Verify: authorisation obtained before credit generation; its conditions complied with; any project change requiring amendment.

Corresponding Adjustment: When an Article 6 credit is transferred internationally, the Government of India applies a corresponding adjustment to India's NDC — recognising that those emission reductions are attributed to the purchasing country and not to India's climate target. The entity must not double-count Article 6 credits for both domestic CCTS compliance and international transfer. Verify: no double-counting; credits transferred internationally have not been used for domestic compliance.

Bilateral Agreement Compliance: Each India-country bilateral agreement has specific rules on eligible project types; credit methodologies; reporting; and pricing. Verify: the specific bilateral agreement applicable to the project; compliance with its rules; government reporting obligations.

FEMA Compliance: Receipt of foreign exchange for international carbon credit transfer is a forex transaction under FEMA 1999. Verify: transaction through authorised dealer bank; FEMA compliance; RBI reporting as required; accounting in books at appropriate exchange rate per Ind AS 21.

Revenue Recognition: International carbon credit sale — Ind AS 115; performance obligation (delivery of the credit with corresponding adjustment documentation) must be completed before revenue is recognised; not on signing of agreement.

13.11 Fraud Risk Indicators — Energy Exchange and Carbon Market

Fraud Scheme	How It Works	Detection Procedure
Exchange trading beyond position limits — speculative trading	Trader exceeds CERC position limits in a session — speculative position taken; losses incurred; concealed from management	Independent pull of exchange trading records from settlement statements; compare with position limits; any session-level breach investigation
DAM purchase when cheaper LT PPA available — kickback	DISCOM schedules less from cheap LT PPA; purchases more expensive DAM electricity; supplier of expensive power pays consideration	Merit order analysis for each day; compare actual scheduling vs merit order; LT PPA capacity vs scheduling; anomaly pattern analysis
REC double-claiming — same generation used twice	RE generator submits same generation data to NLDC for RECs and also sells in G-DAM as RE-attributed power — double revenue	Cross-verify REC application data with G-DAM sales data by technology and generation period; NLDC registry cross-check
ESCert deficit concealment	Energy management team understates actual energy consumption to show SEC achievement — avoiding ESCert purchase obligation	Independent energy consumption data from SCADA; compare with energy management report submitted to BEE; utility bill reconciliation
GHG inventory manipulation	GHG inventory underreports fuel consumption to show lower emissions — supports false	Reconcile GHG inventory fuel consumption data with fuel management (Section 8.2) and energy

Fraud Scheme	How It Works	Detection Procedure
	carbon credit claim or avoids CCTS obligation	charge records; FSA billing; coal stock records; independent recomputation
Carbon credit double-counting	Same emission reduction used for both domestic CCTS compliance and international Article 6 transfer	Cross-check NCR registry records with Article 6 transfer documentation; verify corresponding adjustment applied to Article 6 credits
Excess margin not reclaimed	Exchange margin in excess of trading requirements not reclaimed — left with exchange; interest not earned; possible diversion	Monthly reconciliation of margin deposited vs required; difference must be reclaimed; bank interest computation on excess margin
Electricity derivatives speculation	Trading desk enters derivatives beyond hedge requirement — speculation; losses hidden in mark-to-market accounts	Independent computation of hedge ratio; any derivatives beyond hedge = speculation; Ind AS 109 assessment; P&L mark-to-market impact

14. AUDIT OF FINANCE, TAXATION, TECHNOLOGY AND SUSTAINABILITY FUNCTIONS

14.0 Introduction

Power sector entities — GENCOs, TRANSCOs, DISCOMs, LDCs, and captive mine operators share a set of functional and compliance obligations that run parallel to their primary operational activities and are, in many organisations, the source of the most material audit findings. Fixed assets worth thousands of crores sit in registers that have not been physically verified in years. Insurance covers assets at 2005 cost while 2026 replacement values have trebled. Treasury operations place surplus funds in instruments that the Board has never approved. Tax compliance collapses at the intersection of two Income Tax Acts. Information systems connect operational control systems to corporate networks without meaningful security boundaries.

This chapter consolidates the internal audit framework for ten cross-cutting areas that apply across all entity types: fixed asset management; treasury and cash management; insurance; environment, water and land; procurement and capital works; taxation and statutory compliance; human resources and payroll; information technology and cybersecurity; ESG and sustainability; and the multi-regulatory oversight environment of power sector PSUs. For each area, it states the audit scope, the principal risks, the key procedures and the findings experienced auditors watch for.

This chapter covers the dimensions of each area that carry power-sector-specific risk: CERC treatment of capital spares in asset management; DPE guidelines for treasury; LC management for coal imports; the Income Tax Act 2025 dual-reference framework for taxation; CEA Cyber Security Guidelines 2021 and CERT-In Directions for information security; and the multi-regulatory oversight environment that characterises PSUs in this sector.

14.1 Fixed Asset Management

The Fixed Asset Register is both an accounting record and a regulatory instrument. For regulated GENCOs and TRANSCOs, every capitalised asset, its cost, and its date of commissioning has direct tariff implications as CERC admits capital cost based on prudency assessments, and any variance between book capitalisation and CERC-admitted cost reduces recoverable depreciation and return on equity. This dual role i.e. accounting and tariff is what makes FAR integrity a material audit area in the power sector.

14.1.1 Asset Register Completeness and Physical Verification

Every asset at site must have a FAR entry; every FAR entry must have a corresponding asset at site. The audit starts from the physical — select a sample of major assets at plant, mine, or substation; trace each to the FAR; verify unique tag number, location, date of capitalisation, COD, and cost. Then reverse: select FAR entries and physically verify presence of asset. For DISCOMs, distribution transformers are individually registered by DT number, feeder, and substation; LT line sections by route and voltage. Any FAR entry without a corresponding physical asset is a ghost asset — investigate origin, write-off authority, and any revenue implications.

The Companies Act 2013 and CARO 2020 require the statutory auditor to report whether property, plant and equipment has been physically verified at reasonable intervals; a phased programme covering all assets over three years is generally regarded as reasonable. The audit must verify that the physical verification plan is Board-approved, that rotation coverage is on schedule, and that last-cycle discrepancies have been investigated and the register updated. An asset not verified within the

approved rotation cycle is a material control weakness — even one instance of unexplained missing high-value equipment represents revenue leakage that no subsequent verification can recover.

14.1.2 CERC Prudency and Componentisation

For regulated entities, the capital cost admitted by CERC for tariff purposes must be separately tracked in a reconciliation statement. Items capitalised in books but not admitted by CERC — costs held imprudent, colony and township expenditure, cost overruns beyond DPR without documented justification are carried in books but generate no depreciation or ROE in tariff. The financial impact is the loss of regulatory return on these non-admitted amounts over the remaining useful life of the plant.

Under Ind AS 16, significant components of a major asset with different useful lives must be componentised and depreciated separately. The boiler, turbine, generator, ESP, FGD system, cooling tower, and major transformers of a thermal plant are separate components. Verify: the componentisation policy is documented and applied consistently; depreciation rates for each component correspond to the economic useful life rather than the CERC regulatory life; any major overhaul that replaces a component results in derecognition of the old component and capitalisation of the new one.

Capital Spares (Initial) i.e. spare parts of a capital nature, typically transformer windings, turbine rotors, alternator components, boiler drum assemblies etc., may be capitalised for tariff purposes up to 4% of admitted capital cost under CERC Tariff Regulations 2024-29. The audit must verify that each item in the capital spares list meets the definition — major equipment spare, essential for plant operation, not readily sourceable in an emergency and that the total does not exceed the 4% CERC norm. Misclassification of revenue stores as capital spares inflates admitted capital cost and is a recurrent CERC disallowance area.

14.1.3 Impairment, Decommissioning, and Stranded Asset Risk

Annual impairment assessment under Ind AS 36 is required where indicators are present: sustained operating underperformance, regulatory decisions reducing future revenue, early retirement decisions, geological disappointment at mines. For older thermal units — plants older than 25 years now facing displacement by renewable energy — the recoverable amount of the cash-generating unit may be below carrying value. The cash flow projections must reflect the realistic operating life of the unit, including any policy direction on retirement timelines, rather than assuming operation to the end of the full useful life.

For assets with site restoration obligations like captive mine operators, thermal plants required to decommission ash ponds, hydro projects with dam removal considerations — Ind AS 37 requires recognition of an Asset Retirement Obligation at the present value of estimated future restoration costs at the time of commissioning. The provision must be updated annually for revisions in cost estimates, changes in discount rate, and unwinding. The corresponding amount is added to the carrying value of the asset and depreciated. Any entity that has not recognised an ARO for an applicable asset is carrying an understated liability.

14.2 Treasury and Cash Management

Treasury management in the power sector goes well beyond cash flow management and bank reconciliation. Large GENCOs and state utilities manage multi-thousand-crore investment portfolios, foreign currency exposures from coal imports and external commercial borrowings,

letters of credit as the primary payment instrument for fuel, payment security mechanisms as a commercial obligation to counterparties, and project finance escrow and DSRA structures as lender covenant obligations. Each of these carries specific regulatory requirements and specific fraud risks.

14.2.1 Investment of Surplus Funds

Central PSUs must invest surplus funds only in instruments approved under DPE Guidelines — prescribing eligible instruments, minimum credit ratings, investment limits per issuer, and approval authority levels. State PSUs are governed by state finance department guidelines or their own guidelines. The audit must verify that no investment has been made in a non-approved instrument; that the issuer's credit rating at the time of investment met the minimum required; that approval was at the correct level per Delegation of Financial Powers; and that the maturity profile does not create a liquidity mismatch with operational cash requirements. Any investment in instruments of related parties requires verification of Companies Act 2013 Sections 185 and 186 compliance.

14.2.2 Letter of Credit Management and Foreign Currency Risk

For GENCOs importing coal, Letters of Credit are the primary payment instrument. LC openings must be authorised per DFP; LC terms must match the contract in quantity, quality specifications, delivery terms, usance period, and currency. Any amendment to an LC must be approved by competent authority and confirmed with the counterparty. Document discrepancies between shipping documents and LC terms — if unresolved within the LC validity period can result in the bank refusing payment, disrupting coal supply. An expired LC without utilisation is a supply chain failure and a treasury control weakness.

For entities with External Commercial Borrowings and coal import payments to overseas counterparties, a Board-approved hedging policy must specify which currency exposures are to be hedged, the permitted hedge ratio, approved hedging instruments under FEMA, the maximum forward contract maturity, and the counterparty bank list. Hedge accounting under Ind AS 109 requires formal documentation at inception, effectiveness testing, and recognition of any ineffectiveness through profit and loss. Unhedged foreign currency exposure beyond the Board-approved limits particularly for ECB principal repayments is a risk management failure and a potential FEMA compliance issue.

14.2.3 Payment Security and DSRA Compliance

Every Power Purchase Agreement requires the procurer (DISCOM) to maintain payment security — typically a revolving Letter of Credit for about one month's billing, as specified in the PPA in favour of the generator. From the GENCO's perspective, the audit must verify that every beneficiary DISCOM has a valid, adequately-sized LC in place, renewed before expiry. Any lapsed or inadequate LC exposes the GENCO to default risk and requires invoking the adjudication by CERC under Section 79(1)(f) or the SERC under Section 86(1)(f). From the DISCOM's perspective, maintaining payment security is a condition for continued power supply and a PPA covenant obligation.

For project-financed assets, the Debt Service Reserve Account must be maintained at the level specified in the loan agreement typically one to three months of debt service. DSRA shortfalls trigger lender notification obligations and, if uncured within the prescribed period, may constitute an event of default. The revenue escrow waterfall — operating costs first, debt service second, DSRA

third, equity fourth must be followed precisely every month. Any deviation from the waterfall is a covenant breach requiring documentation and lender notification.

14.2.4 Billing, Accounting and Rebate Compliance

Revenue billing accuracy and rebate management are treasury-adjacent obligations that directly affect cash inflow and counterparty relationships. For GENCOs, every invoice raised on a procurer must be verified for accuracy against the metered energy injected, the applicable tariff components — capacity charges, energy charges, and supplementary charges and any fuel price adjustment for the billing period. Any billing error, whether over or under, creates a reconciliation dispute that delays collection and may result in the procurer netting off disputed amounts against future payments without notice.

Rebate on prompt payment is as specified in the tariff regulations or PPA (under CERC: 1.5% for payment within 5 days and 1% within 30 days). The audit must verify that rebate is extended only where payment was received within the qualifying period, that rebate calculations are mathematically correct against the invoice value, and that rebate granted without qualifying payment — a frequent concession made under relationship pressure is specifically identified and escalated. Turnover Discount extended to bulk consumers or trading counterparties must be documented under a Board-approved policy and verified against the qualifying criteria for each instance.

14.3 Insurance Management Audit

The most common and most material insurance failure in power sector entities is not the absence of cover — it is underinsurance. Assets commissioned at Rs. 2,000 crore in 2005 are still insured for Rs. 2,000 crore (their 2005 cost) in 2026, while the current cost of equivalent replacement may be Rs. 5,000 crore. Under the doctrine of average, this underinsurance applies proportionately to every claim — a partial loss of Rs. 500 crore would recover only Rs. 200 crore. The difference is an unrecoverable loss to the entity. This is not a theoretical risk; it has materialised in major thermal plant incidents in India where insurance proceeds fell dramatically short of reconstruction costs.

14.3.1 Policy Coverage and Sum Insured Adequacy

Policy Category	**Key Audit Requirement**
Material Damage / Engineering All Risk	Sum insured = current replacement value of all assets, not book value. Last independent revaluation date — not more than 3 years old.
Machinery Loss of Profit (MLOP / BI)	Indemnity period 24–36 months for large plant. Gross profit basis. Turnover correctly declared at last renewal.
Boiler and Pressure Plant	All IBR-registered pressure vessels covered. Any new vessel added without insurance endorsement — coverage gap.
Contractor's All Risk (CAR)	Every active capital project above Rs. 10 crore covered. Contractor professional indemnity where design responsibility exists.
Cyber Liability	Coverage specifically includes OT/SCADA breach and business interruption following cybersecurity event.
D&O / Officers Liability	Adequate limit given regulatory proceedings risk. Retroactive date covers pre-policy incidents.
Coal Transit (Marine Cargo)	Institute Cargo Clauses A. Independent surveyor appointment rights for major consignments.

The audit must obtain the latest insurance surveyor's replacement-value report or an independent asset valuation, compare it against the sum insured for each policy, and flag any underinsurance above 10% as a material finding requiring sum insured enhancement at the next renewal.

14.3.2 Claims Management

Late notification is the single most common reason for insurance claim repudiation. Every policy prescribes a notification deadline — typically 24 to 48 hours for major losses and up to 30 days for minor claims. The audit must verify that a notification register is maintained, that all insured events in the period were notified within the prescribed deadline, and that the loss adjuster appointed by the insurer was given access to records without destruction of evidence at the accident site. Any major claim pending beyond 18 months without a surveyor's final report is an accounts receivable risk that requires escalation to the Audit Committee.

Under IRDAI regulations, where the insurer's surveyor has assessed a loss materially below the entity's claim, the insured may seek review of the assessment, including through an independent survey. This right is time-limited, and many entities fail to exercise it, resulting in acceptance of under-assessed claims. The audit must verify that this right was evaluated for all significant contested claims.

14.4 Environment, Water, and Land Management

Environmental non-compliance in the power sector carries consequences that go beyond regulatory penalties — it can result in plant shutdown orders, withdrawal of Environmental Clearance, and NGT-directed compensation that dwarfs any penalty under the Environment Protection Act. Land title deficiencies can halt projects worth thousands of crores at commissioning stage. The internal auditor must treat environmental and land management not as peripheral compliance matters but as material operational risks.

14.4.1 Environmental Compliance

Every power plant and captive mine operates under a set of conditions embedded in the Environmental Clearance and Consent to Operate granted by MoEFCC and the State Pollution Control Board. These conditions are legally binding, individually tracked, and must be complied with on a timeline that does not wait for the entity's convenience. The audit must obtain the current EC conditions list, map each condition to the responsible officer, and verify compliance status. Any condition overdue is a red flag regardless of the perceived severity of the condition.

CEMS data transmitted to the CPCB OCEMS portal must be verified by cross-referencing with stack emission tests by approved laboratories. Data gaps above 5% in any month are both a reporting violation and a potential indicator of equipment manipulation. The water balance — total withdrawal versus consumption versus discharge versus losses — must be prepared monthly and verified against permits. ZLD requirements, where ZLD is an EC or consent condition, permit no process water discharge to external water bodies; any bypass of ZLD infrastructure is a serious violation.

14.4.2 Land Records and Encroachment

The land register must contain every parcel owned or occupied by the entity: survey number, area, taluka, district, nature of title, purpose, and encumbrance status. Title documents must be available for each parcel. Where the entity's name is not yet entered as owner in state revenue records despite completed purchase, mutation proceedings must be tracked to completion — an unmutated title is an unenforceable title, and any land dispute arising on unmutated land will find the entity without

standing in revenue courts. For captive coal mine operators, the land issue is compounded by forest land diversion requirements under the Van (Sanrakshan Evam Samvardhan) Adhiniyam 1980, tribal rights under the Forest Rights Act 2006, and the gram sabha consent in Scheduled Areas under the PESA Act 1996 and the RFCTLARR Act each of which has its own compliance timeline and its own consequence for non-compliance.

Annual boundary survey and physical demarcation of all land parcels must be conducted and documented. An encroachment register must record every encroachment identified, the encroaching party, the nature and extent of encroachment, the date of first identification, and the legal action initiated with current status. For reservoir and catchment areas associated with hydro and pumped storage projects, the catchment area management plan must be verified for implementation — siltation monitoring, catchment treatment works, and restrictions on upstream land use are conditions of the Environmental Clearance and Central Water Commission approval. Any deterioration in reservoir capacity due to unmanaged siltation is both an environmental compliance failure and a material operational risk to generation output. Any land parcel without a title document, without revenue record mutation, or subject to unresolved encroachment represents an unquantified liability that could materialise at project financing or commissioning stage.

14.5 Procurement and Capital Works

Procurement and capital works represent the highest-risk functional area in power sector audit from a fraud and governance perspective. The combination of high-value contracts, technical complexity that limits effective oversight by non-specialists, long-duration contracts with continuous variations, and the pressure to achieve project milestones creates a consistently fertile environment for manipulation. Three decades of CAG audit experience in the sector has established a recurring pattern of manipulation. The internal auditor who knows these patterns and tests for them specifically provides the most effective assurance.

14.5.1 Core Procurement Controls

The Delegation of Financial Powers must be verified for every contract approval, not only for the original award but for every subsequent Variation Order, extension, and price revision. Tenders must be evaluated solely on pre-disclosed criteria; any change to evaluation criteria after bid opening is both a procedural irregularity and a procurement integrity concern. GeM is mandatory for central ministries and departments and required of CPSEs under DPE directions; state PSUs follow state procurement rules — any procurement outside GeM for GeM-available items requires documented justification.

High-Risk Procurement Pattern	**Audit Test**
Single-tender awards above a threshold (e.g. 5% of annual procurement value)	Verify justification, market alternatives, approval above normal DFP level, post-award price reasonableness.
Variation Orders cumulatively exceeding 15% of contract value	Assess whether VO scope was foreseeable at tender stage — foreseeable scope added by VO is untendered work.
Performance Guarantee not enforced on contractor default	Verify PG currency, default trigger documentation, encashment proceedings; any waiver requires Board approval.
Liquidated Damages not levied for delays beyond 30 days	Extract contract schedule vs actual delivery; compute LD entitlement; any LD waiver requires documented approval.

Capital works COD declared without statutory approvals	Verify CEA technical clearance, EC compliance, IBR certificate.
Advance payment outstanding beyond scheduled recovery	Extract advance register; any advance with no recovery milestone within 6 months — immediate action.

14.5.2 Fuel Supply Agreements and MDO Contracts

Fuel Supply Agreements with coal companies are long-term contracts of material financial consequence. Annual Contracted Quantity performance must be tracked monthly — any supply below 75% of the monthly ACQ without a valid force majeure declaration gives rise to a penalty obligation on the coal company under the FSA. This penalty billing is the most commonly missed revenue protection action in GENCO audit. Coal GCV dispute management requires systematic tracking of the 45-day contractual deadline from receipt of sampling reports: any dispute not filed within 45 days is time-barred and the financial claim is irrecoverably lost.

Mine Developer and Operator contracts for captive coal mines require ongoing audit of: MDO production targets versus actual; royalty and statutory payment accountability; coal quality measurement integrity; output measurement at the mine face; and exit provisions. The measurement of Overburden Removal in open-cast mining is a persistent area of MDO contract manipulation — inflated OB removed quantities lead to inflated MDO payments, and the volumetric measurement methodology is technically contestable.

14.5.3 Secondary Fuel Management

Power plants using secondary fuel — Heavy Fuel Oil, Light Diesel Oil (LDO), or gas under a Gas Supply Agreement or Gas Transmission Agreement carry procurement and consumption risks distinct from coal. Secondary fuel is typically procured at market-linked prices with monthly price revisions; any delay in price revision updating in the ERP results in incorrect fuel cost accounting and incorrect FPA computation in tariff billing. The audit must verify: that secondary fuel FSA/GSA/GTA terms including price formula, quantity tolerance, quality specifications, and payment terms are complied with; that actual secondary fuel consumption is reconciled against generation records and heat rate norms for the period of secondary fuel use; that secondary fuel stock at plant is physically verified monthly and reconciled against theoretical consumption; and that any deviation in secondary fuel quality — GCV shortfall, sulphur content above specification — is formally disputed within the contractual deadline.

14.5.4 Consultancy Services Billing Management

Consultancy contracts for project management, engineering design, IT implementation, legal services, and management advisory are a persistent area of procurement risk because the deliverable is intangible, the milestone definition is often subjective, and the verification of completion rests with technical officers who may lack the independence or the incentive to withhold certification. The audit must verify: a scope of work approved at the level prescribed in the DFP; that payment is released only against a completion certificate signed by the designated technical officer and reviewed by the competent authority per DFP; that time-and-material contracts have actual time sheets and material consumption records supporting each billing; and that the total consultancy expenditure for the year is within the Board-approved budget and has not been split across multiple orders to avoid higher approval authority.

14.6 Taxation and Statutory Compliance

Taxation compliance in the power sector is complicated by scale, by transaction diversity, and from April 2026 by the mandatory transition from the Income Tax Act 1961 to the Income Tax Act 2025. Every internal auditor working in the power sector must understand the dual-reference framework that now governs all tax reviews: transactions up to 31 March 2026 are governed by the old Act; Tax Year 2026-27 onwards is governed by the new Act with its numeric Payment Code system. Applying old section numbers to new-year TDS returns, or new codes to old-year assessments, is an error with direct assessment consequences.

14.6.1 TDS Compliance Under Income Tax Act 2025

The TDS payment code transition is not a minor procedural change — it affects every payment made through the ERP from 1 April 2026. Coal transport and O&M contractor payments move from Section 194C to Codes 1023 and 1024. Professional and technical fees move from Section 194J to Codes 1025, 1026, and 1028. Land and equipment rent moves from Section 194I to Codes 1008 and 1009. Coal purchases above Rs. 50 lakh move from Section 194Q to Code 1037. Non-resident payments move from Section 195 to Codes 1039 through 1057. Any ERP system not reconfigured to use the new codes from 1 April 2026 will generate incorrect TDS returns and expose the entity to assessment as a defaulter under Section 398 of the new Act.

Section 37(2)(g) requires that payments to MSME suppliers be made within 45 days as a condition for tax deductibility in the year of accrual. Any MSME payment outstanding beyond 45 days as at 31 March must be added back in computing taxable income. The audit must extract the vendor master for all MSME-registered suppliers, identify all outstanding amounts beyond 45 days at the balance sheet date, and compute the tax disallowance.

14.6.2 GST Compliance

The supply of electrical energy (HSN 2716 00 00) is exempt from GST under Serial No. 104 of Notification No. 2/2017-Central Tax (Rate), dated 28 June 2017, as amended. This exemption creates a compliance obligation to reverse Input Tax Credit on inputs and input services used for the exempt supply, computed monthly under Rule 42 and Rule 43, proportionate to the ratio of exempt turnover to total turnover. An entity that claims full ITC without Rule 42/43 reversal is overclaiming ITC and faces a demand for the reversed amount with interest at 18% per annum and penalty up to the tax amount.

Taxable supplies that coexist with the exempt electricity supply — fly ash sale, REC sale, ESCert sale, FGD gypsum sale, carbon credit sale must be accurately reported in GSTR-1 and matched against GSTR-3B. Mismatches between GSTR-1 and GSTR-3B are a standard GST Department scrutiny trigger. RCM applies to GTA services (where the GTA has not opted for forward charge) for coal transport and to legal services from advocates — any missed RCM liability with no self-invoicing and GSTR-3B reporting is a compliance default.

14.6.3 Cost Audit and Other Statutory Compliance

Power generation entities subject to mandatory cost audit must maintain cost records in CRA-1 format: unit-wise cost sheets capturing Station Heat Rate, Auxiliary Power Consumption, and O&M cost per unit in formats consistent with CAS 1-24. The cost auditor must submit the report in CRA-3 to the Board within 180 days of year end, and the company must file it with MCA in CRA-4 within 30 days of receipt. Any cost audit data that diverges materially from the entity's CERC tariff petition

data without documented explanation is a risk both for CERC proceedings and for MCA compliance.

14.7 Human Resources and Payroll

Headcount reconciliation across HR master, payroll system, and biometric attendance performed for both direct employees and contractor workmen is the primary control over ghost employee risk. In large multi-site PSUs operating across plant, mine, township, and corporate office locations, the reconciliation requires a systematic approach: extract headcount by location and category from all three sources on the same date; identify discrepancies; trace each discrepancy to its resolution. Any biometric attendance system not integrated with payroll for more than three months creates an open door for attendance manipulation. Contractor workforce muster rolls must be compared against attendance-based billing: payment for man-days not supported by attendance records is a direct revenue leakage.

Attendance and leave management require specific audit attention beyond headcount reconciliation. The leave account of every employee must be maintained individually and updated monthly — any accumulation of leave beyond the encashment ceiling without management approval is a contingent liability. LTC claims must be verified against travel records and sanctioning authority approval; any LTC claim where the actual journey is not evidenced by transport tickets and boarding passes is inadmissible. Overtime payments must be verified against the basis of entitlement — whether contractual, statutory under the OSH Code 2020 (earlier the Factories Act), or discretionary and against attendance records for the overtime period; any overtime payment pattern that is uniform across a cadre rather than driven by actual hours worked warrants specific investigation.

HR policy compliance audit must cover the entity's service rules, promotion policy, deputation terms, and contract staff engagement norms. Any promotion made outside the approved promotion policy — bypassing seniority, skipping a grade, or without the required DPC proceedings is both a service matter and an internal control failure. Deputation terms for officers deputed to subsidiaries, joint ventures, or government bodies must be verified: deputation allowance, lien maintenance, and repatriation on expiry of deputation period must all be tracked. Contract staff engagement particularly for technical, IT, and managerial roles must be verified for compliance with applicable labour laws, DPE guidelines on outsourcing, and the entity's own Board-approved contract staffing policy.

Post-retirement employee benefit trusts maintained by power sector PSUs, including Provident Fund Trusts, Self-Contributory Superannuation Benefit (Pension) Trusts, Employees Gratuity Fund Trusts, Leave Encashment Trusts, Post-Retirement Medical Benefit Trusts and Defined Contribution Pension Trusts, require specific internal audit attention. The internal audit function should verify annually that the investment portfolio of each trust, comprising Government Securities and State Development Loans, listed corporate bonds and debt securities, deposits with insurance companies including LIC, and other permitted instruments, complies with the Board-approved investment policy and, the pattern of investment notified by the Ministry of Labour and Employment for exempted PF trusts, the Income-tax Rules for approved gratuity and superannuation funds, and, for CPSEs, applicable DPE guidelines. Investments should be appropriately valued in accordance with the applicable financial reporting framework, including Ind AS 109, using quoted market prices for listed instruments and appropriate valuation techniques for unquoted instruments, wherever applicable. For defined benefit obligations, the amounts recognised in the entity’s financial

statements should be supported by an actuarial valuation by a qualified actuary at each balance sheet date in accordance with Ind AS 19. Key actuarial assumptions, including the discount rate, salary escalation, employee attrition and mortality, should be assessed for reasonableness and consistency with the previous year, and any material change in assumptions should be supported by adequate documentation and justification.

14.8 Information Technology and Cybersecurity

The power sector presents a cybersecurity challenge that is qualitatively different from any other industry: it combines an Information Technology environment with an Operational Technology environment that physically controls generation, transmission, and distribution equipment. A cybersecurity breach in the IT environment results in financial fraud or data loss. A cybersecurity breach in the OT environment can cause power outages across millions of customers, equipment damage valued at hundreds of crores, and safety incidents with fatalities. The internal auditor must audit both environments and they require fundamentally different methodologies.

The CEA Cyber Security Guidelines of 2021 are mandatory for all power utilities and prescribe specific technical and organisational controls. CERT-In Directions of April 2022 impose a 6-hour incident reporting deadline, 180-day log retention, NTP time synchronisation, and vulnerability assessment requirements on all Critical Information Infrastructure operators. The Digital Personal Data Protection Act 2023 creates additional obligations for DISCOMs handling personal data of electricity consumers. The DPDP Rules 2025 were notified in November 2025 with phased commencement; verify the entity's readiness against the applicable dates.

14.8.1 IT General Controls and OT Security

Segregation of Duties conflicts in the ERP are the most material IT-related internal control weakness in power sector entities. The combination of create-vendor-master and approve-payment access in a single user is a fraud gateway — a ghost coal supplier can be created and paid without any other actor's involvement. The combination of raise-PO and approve-PO access enables unauthorised procurement. The SoD matrix must be extracted from the ERP using the GRC tool; every critical conflict must be identified; compensating controls must be verified where conflicts cannot be immediately remediated.

IT-OT network segmentation is the foundational cybersecurity control for power sector OT systems. Bidirectional, unrestricted traffic between the corporate IT network and the OT network allows a compromise that begins in an email attachment to propagate to the SCADA system that controls turbines and transformers. The network boundary must be enforced through a properly configured Industrial Demilitarised Zone with unidirectional security gateways or data diodes on the most critical OT segments. Any OT system running an end-of-life operating system without current vendor security patch support is an extreme vulnerability. Annual Vulnerability Assessment and Penetration Testing by a CERT-In empanelled agency is mandatory; every high and critical finding must have a documented remediation plan with a deadline.

14.8.2 Smart Meters, AI Governance, and Emerging Areas

DISCOMs deploying smart meters under the Revamped Distribution Sector Scheme must ensure that the Head-End System carries security assessment by an approved agency before deployment. Smart meter data is personal data under the DPDP Act 2023 — consumer identification, consumption patterns, payment history, and location data collected from smart meters fall within the

Act's scope. Any DISCOM that has not conducted a DPDP-readiness assessment for its smart meter and consumer data infrastructure is carrying an unquantified compliance liability.

Artificial intelligence applications in power sector operations require a Board-approved AI governance policy covering model validation, explainability, bias assessment, output monitoring, and human override capability. The internal auditor must verify that AI governance is not treated as a technology matter delegated entirely to the IT department as it is a risk management and governance obligation that requires Audit Committee visibility.

14.9 ESG and Sustainability Audit

ESG audit has moved from a voluntary disclosure exercise to a regulated assurance obligation. SEBI requires BRSR for the Top 1000 listed companies; BRSR Core requiring reasonable assurance is mandatory for the Top 150 listed companies. The ICMAI Sustainability Standards (ISS1 and ISS2) and the International Auditing and Assurance Standards Board's (IAASB) International Standard on Sustainability Assurance (ISSA) 5000 provide structured professional frameworks for sustainability reporting and assurance. ISSA 5000 is effective for assurance engagements on sustainability information reported for periods beginning on or after 15 December 2026, with earlier application permitted. For internal auditors in the power sector, the ESG audit mandate is particularly material: the sector is India's largest industrial GHG emitter, its mining operations affect tribal communities and forest land, and its distribution infrastructure handles personal data of hundreds of millions of consumers.

14.9.1 BRSR and GHG Inventory Audit

The internal auditor's role is to verify the underlying data for BRSR disclosures before submission — not to provide the external assurance that SEBI requires for BRSR Core, but to ensure that the data presented for assurance is accurate and traceable to primary records. The most material BRSR data points for power sector entities are: Scope 1 GHG emissions in tCO_2e, reconciled against fuel consumption records and against CEMS data; energy consumption in gigajoules, traceable to meter readings; water withdrawal by source, reconciled against SPCB-permitted withdrawal limits; and total recordable injury rate, reconciled against plant safety records and DGMS reports.

GHG inventory accuracy must be verified using the GHG Protocol Corporate Standard and CEA's CO_2 Baseline Database emission factors. Any discrepancy above 5% between Scope 1 reported emissions and the emissions computed from fuel consumption records is a material BRSR data integrity concern. Carbon credits claimed under CCTS 2023 are based on the same GHG inventory — an overstated inventory overstates carbon credit claims, which is a fraud risk on the National Carbon Registry.

14.9.2 PAT, CCTS, and Stranded Asset Assessment

The Perform, Achieve and Trade scheme requires facilities above the designated consumption threshold to achieve their Specific Energy Consumption target. The M&V report supporting PAT compliance must be prepared by a BEE-accredited expert; the audit must verify that the SEC computation methodology is consistent with the Bureau's prescribed approach, that baseline data has not been manipulated to make the target appear achieved, and that ESCert positions on the BEE portal match the entity's books of account.

For coal-based GENCOs with units older than 25 years, Ind AS 36 impairment assessment under a stranded asset scenario is becoming a material audit area. India's renewable energy trajectory,

CERC's evolving tariff framework for ageing thermal units, and the energy transition policy direction create conditions under which the Value in Use of older coal units may be below carrying value. Any entity that has not conducted an Ind AS 36 assessment for ageing thermal units with clear impairment indicators is carrying an overstated asset.

14.10 Multi-Regulatory Oversight, the MAFR, and the Learning Loop

A large thermal GENCO or state DISCOM operates simultaneously under the oversight of the CAG or State Accountant General, CERC or SERC, the Income Tax Department, the GST Department, Customs, MoEFCC and the State Pollution Control Board, DGMS for mine safety, BEE for energy efficiency, SEBI for listed entities, CVC for Central PSUs, and the entity's own internal audit function. Each oversight body operates on its own timeline, with its own finding format, its own penalty framework, and its own compliance expectations. None of them coordinates with the others.

The Master Audit Findings Register is the instrument through which the internal audit function manages this complexity. It is a single register maintained by the Chief Internal Auditor — updated by the 10th of each month, presented to the Audit Committee quarterly — that consolidates findings from all external oversight bodies into one document showing source, nature, financial amount, responsible officer, compliance deadline, Ind AS 37 provision status, and escalation flag. The MAFR is not a passive record. It is the primary tool for pre-emption: a finding raised by CAG against Unit 1 must trigger an immediate internal audit check at Units 2 through 6 before the CAG inspection party reaches those units. This Learning Loop — external finding in one unit becomes internal audit procedure in all other units is the most practically valuable service that internal audit can provide in a multi-unit power sector PSU.

14.10.1 CAG and Statutory Audit Management

Every Inspection Report paragraph from CAG must be entered in the MAFR immediately on receipt. The entity must submit a factual response within 4 to 6 weeks — this is both a regulatory expectation and, in practice, the entity's only opportunity to provide context that prevents the para from being elevated to a formal Audit Report. Any IR para unresolved beyond two years is at serious risk of CAG Audit Report inclusion, which creates Public Accounts Committee or COPU proceedings and Ministry intervention. The internal audit team must conduct a pre-CAG self-audit in the period immediately before a scheduled CAG inspection — reviewing the areas that CAG has found relevant in previous audit cycles and in comparable entities.

14.10.2 CERC/SERC Disallowance Management and Learning Loop

Every CERC or SERC disallowance in a tariff order must be entered in the MAFR with the financial amount, the basis of disallowance, the remedial action taken for the current petition, and the appeal status for amounts above Rs. 50 crore. The Learning Loop operates specifically at the CERC/SERC interface: a disallowance at Plant A for inadequately justified O&M expenses, or capitalised items outside the scope of power generation, or IDC computed on disputed tranches, must trigger an internal audit check at Plants B, C, and D before their respective tariff petitions are filed.

The compliance calendar for all regulatory filings must be tracked in a single document updated monthly and verified by internal audit quarterly. Any filing overdue by more than 30 days must be escalated immediately. The consequences of delayed regulatory filings in the power sector are not merely financial penalties — they can result in tariff disallowances, plant shutdown orders, and loss of regulatory goodwill that compounds across multiple future proceedings.

14.10.3 Corporate Secretarial Compliance

Corporate secretarial compliance — the ensemble of obligations under the Companies Act 2013 relating to Board governance, statutory registers, regulatory filings, and shareholder communications — is frequently treated as a routine administrative function and consequently receives inadequate internal audit attention. For listed power sector PSUs, the consequence of secretarial non-compliance extends beyond MCA penalty to SEBI enforcement action, stock exchange suspension proceedings, and reputational damage that affects the entity's ability to raise equity capital.

The internal audit programme must verify annually: that Board and Committee meetings are held at the prescribed frequency and that the gap between any two consecutive Board meetings does not exceed 120 days; that minutes are prepared within 30 days of each meeting and signed by the Chairman; that all statutory registers — Register of Members, Register of Directors and KMP, Register of Contracts, Register of Charges — are maintained, updated, and available for inspection; that annual ROC filings — MGT-7, AOC-4, and applicable forms — are filed within prescribed deadlines; that charges created on assets are registered with ROC within 30 days of creation; that related party transaction disclosures in the Annual Report are complete and consistent with the Audit Committee approvals on record; and that the Corporate Governance Report filed with SEBI under LODR Regulation 27 is accurate and consistent with the minutes and registers. Any secretarial audit qualification under Section 204 of the Companies Act 2013 must be entered in the MAFR and tracked to resolution.

14.11 Recurring Findings — Internal Audit Pre-emption Procedures

The following patterns have recurred across CAG Audit Reports on power sector PSUs, CERC and SERC disallowance orders, and DGMS inspection findings over the period from 2010 to 2025. They are not findings against any specific named entity. They recur because the root causes — inadequate tracking systems, absent accountability designations, implicit organisational pressure to avoid awkward findings, and the complexity of CERC regulatory computation — are systemic and common.

Recurring Finding Pattern	Root Cause	IA Pre-Emption Procedure
GCV disputes not filed within 45-day FSA deadline	No tracking of sampling report receipt vs deadline; no designated responsible officer	Monthly extract of third-party sampling reports; compare GCV vs FSA grade; verify dispute filing date; compute time-barred amount
ACQ shortfall penalty not raised on coal company	Monthly ACQ register not maintained; penalty billing not assigned to any officer	Monthly ACQ tracking; penalty computation when supply falls below 75% ACQ; verify penalty bill raised within 30 days
Coal stock physical vs book discrepancy beyond the normal 2–3% range	Physical stock verified annually only; bulk density not validated	Surprise drone/GPS volumetric survey; independent bulk density testing; discrepancy above 5% — investigate pilferage
PAF inflated — forced outages classified as grid	Outage classification by operators under implicit pressure to maintain PAF above 85%	Every "grid constraint" outage — obtain SLDC written instruction; recompute corrected PAF; cross-verify with SCADA

constraint without SLDC instruction		historian
Variation Orders exceeding contract scope	Scope creep normalised; VO approval at lower level than original contract	Original NIT scope vs cumulative VO scope; foreseeability test; VO authority level verification
Capital cost above DPR without justification	Cost increases accepted without pre-filing review	Pre-filing review of all capital additions above DPR cost; engineer certificate for each excess item
O&M expenses above CERC normative	O&M vs normative not tracked in real time	Monthly O&M tracking vs CERC normative; variance above 5% requires documented justification before year-end
Regulatory asset in DISCOM without SERC approval	Revenue shortfalls recorded as regulatory asset without formal SERC order	Verify SERC order for every regulatory asset; un-approved RA is a fictitious asset
R&R delivery below commitment	R&R implementation not given Audit Committee visibility	Field-level verification of R&R delivery against PAP entitlement list; grievance redressal mechanism functioning check
CEMS data gaps above 5% in any month	CEMS maintenance deferred; gaps filled with default values without SPCB notification	OCEMS portal data month-by-month; any gap above 5% — instrument maintenance records and SPCB notification check

14.11.1 Emerging Risk Areas Requiring Proactive Audit Attention

Four emerging risk areas that will move from minor to material in the near term are noted here for proactive inclusion in audit programmes:

Battery Energy Storage System performance manipulation: BESS round-trip efficiency is a contractual and regulatory metric — efficiency figures artificially maintained through selective charging and discharging cycles, or through under-reporting of degradation, distort both the commercial performance record and the impairment assessment under Ind AS 36.

Carbon credit double-counting: with the Carbon Credit Trading Scheme 2023 creating a domestic regulated carbon market alongside voluntary carbon markets, the same GHG reduction can in principle be claimed in both systems. Audit of the GHG inventory should include a check that each reduction is claimed in only one framework and that the National Carbon Registry position reconciles with the MRV plan.

DPDP Act consumer data compliance in DISCOMs: the Digital Personal Data Protection Act 2023 and its Rules (2025) create obligations that DISCOMs are only beginning to map. A DISCOM that has not prepared a data inventory and readiness plan against the phased timelines including appointment of a Data Protection Officer if notified as a Significant Data Fiduciary faces material compliance and breach risk.

AI output integrity: power sector entities deploying AI for generation scheduling, load forecasting, or billing anomaly detection must be audited to verify that AI outputs are subject to human review, that model drift is monitored and managed, and that the basis of AI-influenced decisions is documented and explainable to regulatory authorities.

APPENDICES

APPENDIX 1

CERC TARIFF REGULATIONS 2024-29 — KEY PARAMETERS TABLE

Reference: Section 5.2.1; Sections 8.2 and 8.3

A1.1 Plant Availability Factor (PAF) — Normative Values (Only Benchmark)

Plant Type	Technology	Capacity	Normative PAF
Thermal — Coal	Sub-critical	All sizes	85%
Thermal — Coal	Supercritical	All sizes	85%
Thermal — Coal	Ultra-supercritical	All sizes	85%
Thermal — Gas	Combined Cycle	All sizes	85%
Thermal — Gas	Open Cycle	All sizes	85%
Hydro — Run of River	All	All sizes	As per design
Hydro — Storage	All	All sizes	As per design
Transmission	Lines and Substations	All	98%

A1.2 Station Heat Rate (SHR) — Normative Values (Only Benchmark)

Technology	Unit Size	Normative SHR (Kcal/kWh)
Sub-critical	200 MW and below	2,500
Sub-critical	250 MW	2,450
Sub-critical	500 MW	2,425
Supercritical	500 MW	2,340
Supercritical	660 MW	2,320
Supercritical	800 MW	2,305
Ultra-supercritical	800 MW and above	2,275
Gas — Combined Cycle	All	1,900
Gas — Open Cycle	All	2,800

Note: SHR norms are subject to revision by CERC. Internal auditors must verify the applicable norm from the current CERC Tariff Regulations 2024-29 order for the specific unit.

A1.3 Auxiliary Power Consumption (APC) — Normative Values (Only Benchmark)

Technology	Unit Size	Normative APC (%)
Sub-critical without FGD	200 MW and below	9.0
Sub-critical without FGD	250-500 MW	8.5
Sub-critical with FGD	200 MW and below	9.5
Sub-critical with FGD	250-500 MW	9.0
Supercritical without FGD	500 MW and above	6.0
Supercritical with FGD	500 MW and above	6.5
Ultra-supercritical with FGD	800 MW and above	6.0
Gas — Combined Cycle	All	3.0
Gas — Open Cycle	All	1.5

A1.4 Specific Oil Consumption (SOC) — Normative Values (Only Benchmark)

Plant Type	Normative SOC
All thermal plants	0.30 ml/kWh

A1.5 Financial Parameters

Parameter	CERC 2024-29 Norm
Return on Equity (ROE)	15.5% per annum (pre-tax gross up)
Normative Debt:Equity Ratio	70:30
Interest on Working Capital	SBI MCLR (1-year) + 350 basis points
Normative Receivables	45 days of capacity and energy charges
Coal Stock (working capital)	10 days (pit-head) / 20 days (non-pit-head) of normative fuel cost
Maintenance Spares	20% of O&M expenses
Capital Spares (Initial) Admissible	Up to 4% of admitted capital cost
FGD O&M Norm	As notified separately by CERC

Note: The physical coal stock a plant must hold is governed separately by the CEA coal stocking norms, which depend on distance from the source mine (Section 8.2.3). It is not a tariff parameter.

A1.6 Incentive and Disincentive Framework (Only Benchmark)

Condition	Treatment
PAF at or above 85% normative	Full recovery of annual fixed charges (capacity charges)
PAF below 85% normative	Proportionate reduction in fixed cost recovery; no penalty beyond this
Scheduled energy above normative annual PLF (85%)	Incentive payable per kWh of ex-bus scheduled energy above the normative PLF, at the rates specified in the Regulations separately for peak and off-peak hours
Transmission availability above 98%	Incentive per CERC notification
Transmission availability below 98%	Disincentive; proportionate reduction in ATC recovery

A1.7 Depreciation Rates (Selected Key Assets) (Generalised Rates)

Asset Category	Rate per Year (SLM)
Building (permanent structures)	3.34%
Plant and machinery — generating stations	5.28%
Transmission lines	5.28%
Substation equipment	5.28%
Cable (underground and overhead)	5.28%
Transformers	5.28%
SCADA and control systems	6.33%
Vehicles	11.31%
Office equipment	6.33%
Computers	15.00%

Note: Depreciation rates as per CERC Tariff Regulations 2024-29. These may differ from Companies Act rates — the difference must be reconciled in cost audit and tariff petition preparation.

A1.8 Working Capital Normative Components

Component	**Normative Basis (Indicative)**
Fuel stock (coal)	10 days (pit-head) or 20 days (non-pit-head) of fuel cost at normative SHR and normative fuel price
Advance payment for fuel	30 days of fuel cost
Maintenance spares	20% of O&M expenses
O&M expenses	One month
Receivables	45 days of capacity and energy charges

Note: *The figures shown in this table are representative benchmarks drawn from CERC (Terms and Conditions of Tariff) Regulations 2024-29 for illustrative purposes. CERC 2024-29 prescribes technology-specific norms — PAF, SHR, APC, SOC, O&M, and depreciation schedules vary by unit capacity, fuel type, technology (supercritical/subcritical/gas/hydro), and vintage. Internal auditors must verify the specific norm applicable to the generating station under audit from the entity's CERC tariff petition, applicable tariff order, and Schedule 3 to 7 of CERC Regulations 2024-29. The figures cited here serve as entry-point benchmarks to identify variance — not as universally applicable standards.*

APPENDIX 2

MoEFCC THERMAL POWER PLANT ENVIRONMENTAL STANDARDS MATRIX

Reference: Section 5.7.1; Sections 8.4 and 14.4

A2.1 Emission Standard — Unit Vintage Classification

Vintage	Installation / Commissioning Period	Applicability
I	Units installed up to 31 December 2003	Emission limits applicable to older units; SO_2/FGD requirement and deadline to be determined separately based on the plant's location category under the current MoEFCC framework
II	Units installed after 1 January 2003 and up to 31 December 2016	Applicable intermediate-vintage emission limits; SO_2/FGD requirement and deadline as per current location-category framework
III	Units installed from 1 January 2017 onwards	Applicable new-unit emission limits; SO_2/FGD requirement and deadline as per current location-category framework

A2.2 Emission Standards — MoEFCC Notification S.O. 3305(E), 2015 and Amendments

Parameter	Vintage I	Vintage II	Vintage III	Unit
Particulate Matter (PM)	100	50	30	mg/Nm³
SO_2 — units <500 MW	600	600	100	mg/Nm³
SO_2 — units ≥500 MW	200	200	100	mg/Nm³
NO_x	600	450	100	mg/Nm³
Mercury (Hg)	0.03*	0.03	0.03	mg/Nm³

** Subject to the applicability qualifications contained in the relevant notification for older units.*

Note: The above table identifies emission limits by unit vintage. The present applicability/timeline of SO_2 compliance and consequent requirement for FGD or other SO_2-control measures must be determined separately under the latest MoEFCC amendments, including the 11 July 2025 notification. NO_x for Vintage II was revised to 450 mg/Nm³.

A2.3 SO_2 Compliance — Location Classification

Location Category	Classification	Audit Focus
Category A	Thermal power plants within 10 km radius of NCR or cities having million-plus population	Verify applicable SO_2 standard, notified compliance deadline and implementation of required SO_2-control measures
Category B	Thermal power plants within 10 km radius of Critically Polluted Areas or Non-Attainment Cities	Verify whether SO_2 compliance has been prescribed for the plant under the applicable case-specific framework and the corresponding timeline
Category C	Thermal power plants other than Category A and B	Verify current exemption/applicability under the latest MoEFCC notification and conditions, if any

A2.4 Water Consumption Standards

Plant Type	Water Consumption Norm	Applicability
Existing plants with cooling towers	Maximum 3.5 m^3/MWh	Plants installed before 1 January 2017
Existing plants with once-through cooling	Maximum 3.5 m^3/MWh, after conversion	Must install cooling towers and then meet 3.5 m^3/MWh
New plants installed on or after 1 January 2017	Maximum 3.0 m^3/MWh, plus Zero Liquid Discharge (ZLD)	Norm as amended in 2018; no effluent discharge to external water bodies

Note: Water consumption norms are under MoEFCC notification S.O. 3305(E) dated 7 December 2015, as amended. They depend on installation date and cooling system, not on the SO_2 location category (Appendix A2.3). Verify the norm in the plant's Environmental Clearance and consent conditions.

A2.5 Effluent Discharge Standards

Parameter	Limit	Condition
pH	6.5 to 8.5	All effluent streams
Suspended Solids	100 mg/l	For permitted discharge
Oil and Grease	10 mg/l	For permitted discharge
Arsenic	0.2 mg/l	Ash pond overflow
Fluoride	2 mg/l	Cooling tower blowdown

Note: For plants installed on or after 1 January 2017, and for any plant where ZLD is an EC or consent condition, no discharge to an external water body is permitted. The above limits apply to permitted discharges and to any emergency overflow only.

A2.6 Ash Utilisation Requirements

Requirement	Standard
Fly ash utilisation	100% of fly ash generated (including legacy ash) to be utilised within the compliance cycle under the MoEFCC Fly Ash Notification of 31 December 2021; environmental compensation for shortfall
Use of fly ash in the vicinity	Fly ash to be made available for construction, brick-making and other notified uses within 300 km of the plant, as specified in the 2021 notification
Fly ash utilisation report (CPCB portal)	Annual, by the notified due date
Ash pond third-party safety inspection	Annual
FGD gypsum disposal	Sale/disposal records; authorised recyclers only

A2.7 Audit Quick Reference — Environmental Compliance Checks

Audit Check	Source Document	Frequency

Audit Check	Source Document	Frequency
CEMS real-time data on OCEMS portal	CPCB OCEMS portal	Continuous; reviewed monthly
Stack emission test by approved lab	Lab report	Quarterly
EC half-yearly compliance report	MoEFCC/SPCB	Half-yearly
CTO renewal (SPCB)	CTO certificate	Before expiry (validity per CTO)
Fly ash utilisation report (CPCB portal)	CPCB acknowledgement	Annual
Water withdrawal log vs permit	Water meter + licence	Monthly
Ash pond stability certificate	Third-party certificate	Annual
Hazardous waste manifest records	Form 10	Every movement

APPENDIX 3

INCOME TAX ACT 2025 — DUAL REFERENCE TABLE

Reference: Sections 5.9 and 14.6.1

A3.1 Overview

The Income Tax Act 2025 came into force on 1 April 2026. It replaces the Income Tax Act 1961. For the transition period:

- ✓ Transactions up to 31 March 2026 — governed by Income-tax Act, 1961 (old sections)
- ✓ Tax Year 2026-27 onwards (from 1 April 2026) — governed by Income Tax Act 2025 (new sections and codes)
- ✓ Legacy assessments; appeals; proceedings — continue under Income-tax Act, 1961 for the year of income concerned

A3.2 Key Section Cross-Reference Table

Subject	Income-tax Act, 1961 — Old Section	Income Tax Act 2025 — New Section/Provision	Applicability Date
Income from salaries	Section 15-17	Section 15-19	From 1 April 2026
Income from house property	Section 22-27	Section 20-25	From 1 April 2026
Income from business/profession	Section 28-44	Section 26-66	From 1 April 2026
Disallowances (general)	Section 40; 40A; 43B	Section 35-37	Both — check year
MSME payment disallowance	Section 43B(h)	Section 37(2)(g)	From 1 April 2026
Capital gains	Section 45-55A	Section 67-91	From 1 April 2026
Deduction for power undertakings	Section 80IA	Section 147	Both — check year
Concessional tax — manufacturing	Section 115BAB	Section 201, Deadline 31 March 2024 passed	Legacy only
Minimum Alternate Tax	Section 115JB	Section 206	Both — check year
Tax deduction at source	Chapter XVII-B	Chapter XIX-B — Sections 392–398	From 1 April 2026
Tax audit report	Section 44AB; Form 3CD	Section 63; Form No. 26	From Tax Year 2026-27
Transfer pricing	Section 92-92F; Form 3CEB	Sections 161–173; reporting under Section 172; Form No. 48	From Tax Year 2026-27
Country-by-Country Report	Section 286	Section 511	Both — check year
Assessment procedure	Section 143-147	Sections 270, 279-285	Both — check year
Appeals	Section 246A-263	Sections 356–379	Both — check year

Subject	Income-tax Act, 1961 — Old Section	Income Tax Act 2025 — New Section/Provision	Applicability Date
Penalties	Section 270A-275	Chapter XXI — Sections 439 onwards	Both — check year
Prosecution	Section 276-280	Chapter XXII — principally Sections 473–494	Both — check year
Interest for default	Section 234A; 234B; 234C	Sections 423–425	Both — check year

A3.3 TDS Payment Codes — Power Sector Reference (From 1 April 2026)

Nature of Payment	Old Section (Income-tax Act, 1961)	New Payment Code (Income Tax Act 2025)	Rate — Company	Rate — Individual /HUF	Power Sector Application
Contractor payments — works and services	Section 194C	Code 1023/1024	2%	1%	Coal transport; O&M contracts; civil works; MDO; construction
Professional and technical fees	Section 194J	Code 1025/1026/1028	10%	10%	Consultants; lawyers; engineers; CA/CMA fees
Rent — land; building; plant	Section 194I	Code 1008/1009	10% (land/ building); 2% (plant/ machinery)	Same	Land lease; equipment hire; office rent
Purchase of goods above Rs. 50 lakh	Section 194Q	Code 1037	0.1%	0.1%	Coal purchase from CIL/SCCL above threshold
Purchase of immovable property	Section 194IA	Code 1010	1%	1%	Land acquisition for plant; mine; substation
Salary	Section 192	Code 1002	As per slab	As per slab	All employees
Interest — bank deposits; others	Section 194A	Code 1017	10%	10%	Interest on loans/deposits from non-bank lenders; interest paid to banks is not subject to TDS
Dividends	Section 194	Code 1031	10%	10%	Dividend to shareholders

Nature of Payment	Old Section (Income-tax Act, 1961)	New Payment Code (Income Tax Act 2025)	Rate — Company	Rate — Individual /HUF	Power Sector Application
Non-resident payments	Section 195	Code 1039-1057	As per DTAA or 20%+	Same	Coal import payments; foreign OEM fees; ECB interest
TDS on GST component	All sections	Not applicable	GST excluded from TDS base	Same	Verify GST amount excluded from TDS calculation

A3.4 New Form Numbers (From Tax Year 2026-27)

Purpose	Old Form	New Form	Filing Due Date
TDS return — salary	Form 24Q	Form 138	31 July; 31 October; 31 January; 31 May
TDS return — non-salary	Form 26Q	Form 140	Same as above
TDS certificate — salary (annual)	Form 16	Form 130	15 June after year end
TDS certificate — non-salary (quarterly)	Form 16A	Form 131	15 days after each quarter
Tax Audit Report (including TP)	Form 3CD and Form 3CEB	Form 26 and Form 48	Before ITR due date
Income Tax Return — company	ITR-6	form number as notified	31 October; extended for audit cases
Application for lower TDS	Form 13	Form 128	Before payment

A3.5 Key Transition Dates and Compliance Milestones

Date	Milestone	Action Required
1 April 2026	Income Tax Act 2025 effective	ERP TDS configuration updated to new payment codes
15 June 2026	Form 130 (salary TDS certificate) due	Issue to all employees for Tax Year 2026-27
15 July 2026	Form 131 (non-salary TDS certificate) — Q1	Issue to all deductees for Q1 Tax Year 2026-27
31 July 2026	Form 138 and 140 (TDS returns) — Q1	First quarterly return under new form numbers
27 September 2026	CRA-3 cost audit report filing	180 days from 31 March 2026 year end
31 October 2026	ITR filing for Tax Year 2025-26	Final year under Income-tax Act, 1961 for this purpose
Before ITR filing	Form 26 (Tax Audit Report) and Form 48 (Transfer Pricing Report)	New form numbers from Tax Year 2026-27 onwards; Form 26 replaces Form 3CD and Form 48 replaces Form 3CEB

APPENDIX 4

GST TRANSACTION MATRIX — POWER SECTOR

Reference: Sections 5.10 and 14.6.2

A4.1 Complete GST Transaction Matrix

#	Transaction	GST Treatment	Rate	ITC Availability	Key Audit Check
1	Supply of electricity to consumers or buyers	S. No. 104 of Notification 2/2017-CT (Rate), CGST Rate Notification	Nil	ITC on inputs must be reversed under Rule 42/43	Verify no GST charged; verify Rule 42/43 reversal computed monthly
2	Coal supply — domestic (CIL; SCCL; captive mine)	Taxable	18% (CGST 9% + SGST 9% or IGST 18%)	Available; subject to Rule 42/43 proportionate reversal	Verify ITC claimed in GSTR-3B Table 4; Rule 42/43 reversal applied
3	Coal supply — imported	Taxable	IGST at 18% on assessable value (CIF + BCD + AIDC + SWS)	Available	Verify IGST on Bill of Entry; ITC in GSTR-2B from Bill of Entry data
4	Works contract — civil construction of plant	Taxable	18% GST	Blocked under Section 17(5)(c) for civil works attached to earth	No ITC for civil works; verify correct bifurcation from civil vs P&M claim; ITC only on P&M portion
5	Works contract — plant and machinery erection	Taxable	18% GST	Available — Full ITC available	Verify correct bifurcation from civil; claim ITC
6	Capital goods — transformers; turbines; switchgear; meters	Taxable	18% (specified RE equipment at 5%)	Available in proportionate year of receipt; Rule 42/43 reversal for exempt supply	Verify HSN and rate; claim ITC; apply Rule 43 reversal

7	ISTS charges billed by CTUIL	Exempt	Nil	Not Applicable	Verify no GST charged on transmission charges; GST applies to ancillary services billed separately
8	O&M services	Taxable	18% GST	Available where applicable	RCM if services from unregistered; verify RCM where applicable
9	Goods Transport Agency (GTA) — coal transport	Taxable	5% (without ITC) or 18% (with ITC); RCM applicable	Available after RCM payment	Recipient (GENCO/DISCOM) pays GST under RCM; verify RCM liability computed and paid; ITC after payment; filed in GSTR-3B
10	Security services	Taxable	18% GST; RCM if supplier is individual	Available after RCM	Verify RCM where applicable; ITC claim
11	Fly ash sale	Taxable	5% GST	Available on inputs for fly ash-related activity	Fly ash is taxable; Rule 42/43 must be applied to distinguish exempt (electricity) from taxable (fly ash) supplies
12	REC sale	Taxable	18% GST	Available on inputs for REC-related activity	REC is an intangible asset sold — taxable at 18%; verify GST charged on REC sale invoice
13	ESCert sale	Taxable	18% GST	Available	Same as REC — taxable intangible; verify GST
14	Carbon credit sale — domestic CCTS	Taxable	18% GST (tentative — verify current GST Council notification)	Available	Emerging area — verify current GST position
15	Electricity duty collected from consumers	Not subject to GST	Nil	Not applicable	Electricity duty collected as agent of state government; not GST taxable; not to be included in turnover

16	Late payment surcharge (LPS) on consumer bills	Exempt	Nil	Not applicable	Verify no GST charged; LPS forms part of the exempt supply of electricity (CBIC Circular 178/10/2022)
17	Employee canteen — subsidised meal	Taxable	5% GST (restaurant services)	Blocked under Section 17(5)(b)	No ITC on employee canteen; blocked category
18	Insurance premium	Taxable	18% GST	Available for business insurance	Verify GST charged on all insurance policies; ITC claimed for business purpose insurance
19	Legal and professional fees	Taxable	18% GST	Available	RCM for legal services from advocate; verify

A4.2 Rule 42/43 Reversal — Quick Computation Reference

Rule 42 — Inputs and Input Services:

Monthly computation:

1. Common credit (C2) = Total ITC − ITC exclusively for exempt supplies (T2) − ITC for non-business use (T1) − blocked credit (T3) − ITC exclusively for taxable supplies (T4)
2. Reversal for exempt supply (D1) = C2 × (Exempt turnover ÷ Total turnover)
3. Reverse D1 monthly in GSTR-3B; true up annually.
4. Exempt turnover for GENCO = Value of electricity supplied = Units sold × Applicable tariff
5. Taxable turnover = Fly ash sales + REC/ESCert sales + Other taxable supplies

Rule 43 — Capital Goods:

Monthly computation:

1. Total ITC on capital goods received in the month (Te)
2. Common credit = Te/60 (per month for 5-year life)
3. Reversal = (Te/60) × (Exempt turnover ÷ Total turnover) for the month
4. Accumulated over 60 months

Annual reversal reconciliation:

At year end — compute annual proportion of exempt to total turnover; compare with sum of monthly provisional reversals; any difference — adjusted in September GSTR-3B or GSTR-9.

APPENDIX 5

LABOUR LAW MATRIX — POWER SECTOR

Reference: Sections 5.12 and 14.7

A5.1 Four Labour Codes — Status and Power Sector Implications

Code	Enacted Year	Status as at publication	Key Power Sector Provision	Audit Implication
Code on Wages 2019	2019	In force from 21 November 2025; state rules being notified	Minimum wage; overtime; equal pay; bonus — covers all employees including contract workers	Verify minimum wage compliance for direct and contract workers; verify overtime limits
Industrial Relations Code 2020	2020	In force from 21 November 2025; state rules being notified	Standing orders; collective bargaining; retrenchment; lay-off; strike	Verify standing orders certified for establishments above 300 workers; IR compliance for mine disputes
Social Security Code 2020	2020	In force from 21 November 2025; state rules being notified	EPF; ESI; gratuity; maternity; building workers; unorganised workers	Verify EPF ECR; ESI contribution; BOCW registration; gratuity trust funding
OSH Code 2020	2020	In force from 21 November 2025; state rules being notified	Safety; health; working conditions for factories; mines; construction; plantation	Verify OSH compliance for power plants (factory); mines (separate mine provisions); construction sites

A5.2 Earlier Labour Laws Subsumed in the Codes — Transitional Reference

Law	Applies To	Key Power Sector Provision	Key Audit Check
Factories Act 1948	Power plant premises (factory)	Safety; welfare; working hours; annual leave	Factory licence; inspection compliance; welfare amenities
Mines Act 1952 (subsumed in OSH Code 2020)	Captive coal mines	Safety; accident reporting; manager qualifications; working hours underground	Refer Section 9.4 in full
Contract Labour (Regulation and Abolition) Act 1970	All entities engaging contract labour	Principal employer registration; contractor licence; welfare	PE registration; contractor licence; form returns
Building and Other Construction Workers Act 1996	All capital construction activities	BOCW Cess at 1%; worker registration; welfare benefits	Cess computation; payment; worker registration

Law	Applies To	Key Power Sector Provision	Key Audit Check
Employees' Provident Funds and Miscellaneous Provisions Act 1952	All entities with 20+ employees	EPF at 12% employer; 12% employee; EPS 8.33% of employer portion	ECR accuracy; timely payment by 15th; UAN for all
Employees' State Insurance Act 1948	Employees in factory/establishment with 10+ employees; wages below Rs. 21,000/month	ESI — employer 3.25%; employee 0.75%	Coverage of all eligible employees; monthly payment
Payment of Gratuity Act 1972	All entities with 10+ employees	Gratuity — 15 days per year of service; maximum Rs. 20 lakh	Actuarial valuation; trust funding; Ind AS 19
Maternity Benefit Act 1961	Establishments employing women	26 weeks maternity leave; creche; medical bonus	Compliance for all women employees; contract women workers
Sexual Harassment of Women at Workplace Act 2013	Applies to all workplaces; an ICC is mandatory where 10 or more are employed	ICC; complaint mechanism; annual report	ICC constitution; external member; annual report to District Officer
Inter-State Migrant Workmen Act 1979	Entities engaging inter-state migrant workers	Displacement allowance; journey fare; facilities	Migrant worker identification; entitlement delivery
Child and Adolescent Labour (Prohibition and Regulation) Act 1986 (as amended in 2016)	All entities	No child below 14 in any employment; no adolescent (14–18) in hazardous occupations including mines	Age verification for all workers including contractors; mine entry records
Equal Remuneration Act 1976	All entities	Equal pay for equal work regardless of gender	Payroll analysis — gender pay gap for same grade same function

Note: Except the Sexual Harassment of Women at Workplace Act 2013 and the Child and Adolescent Labour (Prohibition and Regulation) Act 1986, which remain in force, these laws were subsumed in the four Labour Codes from 21 November 2025. They continue to apply to obligations for periods before that date, and rules or regulations made under them continue to the extent preserved under the transitional provisions until replaced.

A5.3 Statutory Compliance Calendar — Labour Laws

Compliance	Frequency	Due Date	Authority

Compliance	Frequency	Due Date	Authority
EPF Electronic Challan cum Return (ECR)	Monthly	15th of following month	EPFO
ESI Contribution	Monthly	15th of following month	ESIC
Professional Tax deduction and remittance	Monthly	Varies by state (5th or 10th)	State PT Authority
BOCW Cess payment	Per project; quarterly or on UC	Within 30 days of triggering	State BOCW Welfare Board
Factories Annual Return	Annual	31 January	State Factory Inspector
Factories Half-yearly Return	Half-yearly	31 July; 31 January	State Factory Inspector
Mines Annual Return	Annual	As prescribed by DGMS	DGMS
POSH Annual Report	Annual	31 January	District Officer
Contract Labour Annual Return	Annual	February	Labour Commissioner
Gratuity Trust Annual Report	Annual	Per Trust Deed	Registrar of Trusts

APPENDIX 6

REGULATORY FILING CALENDAR — POWER SECTOR

Reference: Sections 5.16 and 14.10.2

A6.1 Complete Regulatory Filing Calendar

Filing	Authority	Frequency	Due Date	Responsible Department	Consequence of Default
Tariff / ARR Petition	CERC/SERC	Annual	As per CERC/SERC schedule (typically October-November for next year)	Finance/ Regulatory	Interim tariff; CERC/SERC proceeding delay
Tariff True-Up Petition	CERC/SERC	Annual	As per CERC/SERC schedule	Finance/ Regulatory	Revenue loss; delayed recovery
Monthly Generation Data (CEA NPP)	CEA (National Power Portal)	Monthly	7th of following month	Operations	CEA notice; data gap
FPA Invoice to beneficiaries	Beneficiary DISCOMs	Monthly	Within 30 days of month end	Finance	Revenue leakage
EC Half-Yearly Compliance Report	MoEFCC/SPCB	Half-yearly	1 June and 1 December	Environment	MoEFCC notice; EC suspension risk
CEMS Data — OCEMS Portal	CPCB	Continuous (real-time)	Continuous	Environment/ Operations	CPCB violation; SPCB notice
Fly ash utilisation report (CPCB portal)	CPCB	Annual	As per due date	Environment	CPCB notice; fly ash rule violation
CTO Renewal Application	SPCB	Annual (before expiry)	60 days before CTO expiry	Environment	Lapse of CTO; operations risk
Stack Emission Monitoring Report	SPCB	Quarterly	15th of following quarter	Environment	SPCB notice
Royalty Payment	State Government	Monthly	15th of following month	Finance (Mine)	Penalty; interest; MMDR violation

Filing	Authority	Frequency	Due Date	Responsible Department	Consequence of Default
DMF Contribution	DMF Trust	Monthly	15th of following month	Finance (Mine)	MMDR Act violation; prosecution
DGMS Quarterly Report	DGMS	Quarterly	15th of following quarter	Mine Safety	DGMS notice; prosecution
RPO Compliance Certificate	SERC	Annual	As per SERC notification (typically July for previous year)	Regulatory/ Commercial	SERC penalty for non-compliance
REC Application to NLDC	NLDC REC Registry	Monthly	Within 180 days of generation month	Regulatory/ Commercial	Time-barred; revenue loss
GSTR-1 (Outward Supplies)	GST — GSTN Portal	Monthly	11th of following month	Finance	Late fee; GSTR-2B impact
GSTR-3B (Summary Return and Tax Payment)	GST — GSTN Portal	Monthly	20th of following month	Finance	Late fee; interest; penalty
GSTR-9 (Annual Return)	GST — GSTN Portal	Annual	31 December	Finance	Late fee Rs. 100/day
GSTR-9C (Reconciliation Statement)	GST — GSTN Portal	Annual	With GSTR-9	Finance/ CA-CMA	Penalty for non-filing
Advance Tax — Instalments	Income Tax Department	Quarterly	15 June (15%); 15 September (45%); 15 December (75%); 15 March (100%)	Finance	Sections 424–425 of the 2025 Act
Income Tax Return	Income Tax Department	Annual	31 October (audit cases); extended as notified	Finance	Late fee; interest; prosecution
Form 26 & 48 (Tax Audit and TP Report)	Income Tax Department	Annual	Before ITR filing	Finance/Tax Consultant	Disallowance of 147; TP adjustment
CRA-2 (Cost Auditor Appointment)	MCA	Annual	Within 180 days or 30 days of Board approval	Finance/Secretarial	Companies Act penalty

Filing	Authority	Frequency	Due Date	Responsible Department	Consequence of Default
CRA-3 (Cost Audit Report)	MCA	Annual	CRA-3 to Board within 180 days; CRA-4 to MCA within 30 days of receipt	Finance/Cost Auditor	Penalty under Section 148(8)
Annual Report and Financial Statements	MCA/ROC	Annual	AOC-4 within 30 days and MGT-7 within 60 days of AGM	Finance/Secretarial	MCA penalty; ROC notice
Board Report (CSR; BRSR for listed)	MCA/SEBI	Annual	With Annual Report	Secretarial/ Finance/ESG	MCA; SEBI penalty
SEBI Quarterly Financial Results	Stock Exchanges	Quarterly	45 days from quarter end	Finance/ Secretarial	SEBI penalty; trading suspension
EPF ECR Filing and Payment	EPFO	Monthly	15th of following month	HR/Finance	Interest 12%; damages 5-25%
ESI Filing and Payment	ESIC	Monthly	15th of following month	HR/Finance	Interest; prosecution
Electricity Duty Remittance	State Government	Monthly	Varies by state	Finance/ Commercial	Interest; state penalty
BRSR (Top 1000 listed — mandatory)	SEBI/Stock Exchange	Annual	With Annual Report	Secretarial/ Finance/ESG	SEBI LODR penalty
BRSR Core Assurance Phased — top 150 from FY 2023-24, widening thereafter	SEBI/Stock Exchange	Annual	With Annual Report	Secretarial/ ESG/Assurance Provider	SEBI LODR penalty

APPENDIX 7

CEA CYBER SECURITY GUIDELINES 2021 — POWER SECTOR COMPLIANCE SUMMARY

Reference: Section 5.14.4; Sections 14.8.1 and 14.8.2

A7.1 Overview

The CEA (Cyber Security in Power Sector) Guidelines, issued in October 2021, apply to all power sector utilities — GENCOs; TRANSCOs; DISCOMs; LDCs. These guidelines create enforceable cybersecurity obligations and must be tracked as a compliance requirement alongside MoP's general regulatory oversight.

A7.2 Selected Key Requirements and Compliance Verification

Requirement Area	Guideline Section	Key Requirement	Audit Evidence
Training and awareness	Section 12	Annual cybersecurity training for all staff; OT-specific training for control room operators	Training records; attendance; assessment
Third-party vendor risk	Section 13	Vendor security assessment; contractual security obligations	Vendor assessment records; contract terms
Remote access controls	Section 14	Controlled remote access; MFA; session logging	Remote access policy; access logs
Security operations monitoring	Section 15	Security monitoring tools; alert response	SIEM or equivalent; alert logs
Compliance reporting	Section 16	Annual compliance report to CEA	Compliance report filed

A7.3 CERT-In Directions 2022 — Compliance Checklist

Requirement	Deadline	Compliance Action	Verification
Report cybersecurity incident to CERT-In	Within 6 hours of detection	Incident reporting procedure; designated CERT-In reporter	Incident log; notification timestamps
Maintain ICT system logs	180 days minimum retention	Log retention policy; storage capacity	Log configuration; retention verification
Synchronise all system clocks	With NPL or NIC NTP server	NTP configuration on all systems	NTP server IP in system configuration
Annual VAPT by CERT-In empanelled agency	Annual	VAPT scheduled; agency selected from CERT-In empanelled list	Agency verification on CERT-In website; VAPT report
Virtual asset reporting	As applicable	VDA dealing reported	Not typically applicable to power sector

APPENDIX 8

MASTER LEGISLATIVE MATRIX — POWER SECTOR

Reference: Chapter 5 (all sections); used as quick reference across all entity chapters

A8.1 Complete Legislative Reference Matrix

Law/Regulation	Year	Key Provisions	Applicable Entities	Key Audit Implication
Electricity Act 2003	2003	Section 62 (cost-plus tariff); Section 63 (competitive bid); Section 126 (assessment); Sections 135–140 (theft); Section 42 (CGRF; open access); Section 2(8) (captive plant)	All power sector entities	Tariff framework; consumer protection; captive plant rules
Electricity (Amendment) Rules 2023	2023	Revised captive plant definition Rule 3; 51% self-consumption; Rule 19 RE tariff	All	Captive plant compliance; RE tariff verification
CERC Tariff Regulations 2024-29	2024	PAF 85%; SHR norms; ROE 15.5%; Capital Spares (Initial) 4%; working-capital coal stock 10 days (pit-head) / 20 days (non-pit-head)	GENCOs; TRANSCOs regulated by CERC	Tariff KPIs; prudency norms
OSH Code 2020 (subsuming Mines Act 1952)	2020	Manager certificate; accident reporting; SCSR; safety committee; prosecution	Integrated GENCO (captive mine)	Safety compliance; accident notification
MMDR Act 1957	1957	Royalty; DMF; NMET; Coal Dispatch Annual Return; mining lease	Integrated GENCO (captive mine)	Statutory payments; returns
Coal Mines (Special Provisions) Act 2015	2015	Block allotment conditions; end-use restriction; revenue share; monitoring committee	Integrated GENCO	Block compliance; end-use restriction
Environment Protection Act 1986	1986	EC conditions; MoEFCC standards; environmental compliance	All (generating plants; mines)	EC compliance; CEMS; ash; water
Van (Sanrakshan Evam Samvardhan) Adhiniyam 1980	1980	Forest clearance Stage I and II; CA; NPV	Any entity on forest land	FC conditions; CA status

Law/Regulation	Year	Key Provisions	Applicable Entities	Key Audit Implication
Dam Safety Act 2021	2021	Dam Safety Unit; pre- and post-monsoon inspections; periodic comprehensive safety evaluation by an independent panel; EAP	Hydro power entities	Dam safety compliance
Energy Conservation Act 2001 (Amended 2022)	2001	PAT scheme; DC designation; SEC target; ESCert; CCTS	Thermal plants above 30,000 toe; large utilities	PAT compliance; ESCert; CCTS
Companies Act 2013	2013	Section 138 (internal audit); Section 135 (CSR); Section 177 (AC; whistleblower); Section 148 (cost audit)	All corporate entities	Internal audit mandate; CSR; governance; cost audit
Income Tax Act 2025 (from 1 April 2026)	2025	TDS payment codes; Form 130/131/138/140/26; Section 37(2)(g); Section 147	All entities	TDS compliance; deductions; TP
CGST Act 2017	2017	Exempt supply (electricity); ITC; Rule 42/43; GSTR filing	All entities	GST compliance; ITC reversal
Customs Act 1962	1962	HS 2701 (coal); BCD; IGST; valuation	Coal-importing GENCOs	Import compliance; duty; TP
FEMA 1999	1999	ECB; forex remittance; hedging; LC	All entities with forex exposure	FEMA compliance; ECB reporting
RFCTLARR Act 2013	2013	Land acquisition; SIA; compensation; R&R	GENCOs; TRANSCOs with land acquisition	Land compensation; R&R delivery
IT Act 2000 (Amended 2008)	2000	CII; Section 70; CERT-In Directions	Notified protected systems (CII)	Cybersecurity compliance; incident reporting
DPDP Act 2023; DPDP Rules 2025	2023 & 2025	Personal data protection; Data Fiduciary; Data Principal rights; breach notification	All entities handling consumer and employee data	Consumer data protection; breach notification
Public Premises Act 1971	1971	Eviction of unauthorised occupants from government/PSU premises	All PSU entities with townships	Township quarter management
Boilers Act 2025 / IBR 1950	2025/ 1950	Boiler registration; IBR certificate; pressure vessel inspection	GENCOs with boilers	IBR compliance; pressure vessel safety

APPENDIX 9

GOVERNMENT SCHEMES AND POLICY INSTRUMENTS MATRIX — POWER SECTOR

Reference: Section 4.5; cross-referenced throughout entity chapters

A9.1 Government Schemes — Audit Implications Reference

Scheme	Year	Objective	Key Audit Implications	Relevant Entity	Chapter Reference
National Electricity Policy 2005	2005	Universal access; AT&C reduction; rural electrification	AT&C loss audit baseline; rural electrification targets	DISCOM	Section 5.5
National Tariff Policy 2016	2016	Tariff determination principles; RPO; ISTS charge waiver for RE; must-run status	RPO compliance audit; cross-subsidy reduction	All	Section 5.5
SHAKTI Policy 2017	2017	Coal linkage rationalisation; e-auction; GENCO fuel security	FSA; LoA; BG compliance; e-auction participation	Thermal GENCO	Sections 4.5 and 8.2.1
PM-KUSUM 2019	2019	Solar pump for agriculture; rooftop solar; feeder-level solar	Procurement compliance; subsidy disbursement; DISCOM power purchase from PM-KUSUM sources	DISCOM; RE GENCO	Section 4.5
FAME-II 2019 succeeded by PM E-DRIVE	2019	EV adoption; EV charging infrastructure	EV charging tariff audit; EV charging metering; DISCOM demand response	DISCOM	Sections 4.5 and 12.9
RDSS 2021	2021	DISCOM infrastructure upgrade; smart meters; AT&C reduction; financial turnaround	Grant utilisation; UC accuracy; smart meter installation; DT metering; AT&C milestone	DISCOM	Sections 4.5 and 12.5

Scheme	Year	Objective	Key Audit Implications	Relevant Entity	Chapter Reference
CEA Cyber Security Guidelines 2021	2021	Cybersecurity for power sector as CII	Annual VAPT; CIRP; IT-OT segmentation; supply chain security	All	Section 5.14.4; Appendix 7
Electricity (Amendment) Rules 2023	2023	Revised captive plant definition; 51% self-consumption; Rule 19 RE tariff	Captive plant compliance	All	Section 5.1.2; Ch.7
Energy Storage Obligation — MoP Order 22 July 2022	2022	ESO trajectory; BESS alongside RE	BESS performance audit; ESO compliance verification	GENCO; DISCOM	Sections 5.2.9 and 10.5
Carbon Credit Trading Scheme 2023	2023	Domestic carbon market; GHG reduction; credit trading	GHG inventory; MRV; NCR registration; credit accounting	Entities in notified sectors (power sector targets pending)	Sections 5.7.9 and 13.9
National Green Hydrogen Mission 2023	2023	Green hydrogen production; SIGHT incentive	SIGHT incentive accounting; electrolyser capitalisation; PESO; green certification	GH_2 producers	Sections 4.5 and 10.8
MoP Guidelines to Promote Development of Pump Storage Projects 2023	2023	PSP development	PSP tariff audit; RTE computation; upper/lower reservoir compliance	Hydro GENCO	Sections 4.5 and 10.4
PM Surya Ghar Muft Bijli Yojana 2024	2024	Rooftop solar for residential consumers; free units; subsidy	Subsidy disbursement; beneficiary verification; net meter installation; vendor empanelment	DISCOM	Sections 4.5 and 12.9.2
CERC Tariff Regulations 2024-29	2024	Tariff norms for 5-year period	All GENCO and TRANSCO tariff audit parameters	GENCO; TRANSCO	Section 5.2.1; Appendix 1

APPENDIX 10

FRAUD RISK REFERENCE — CONSOLIDATED

Reference: All entity audit chapters; Chapter 14

A10.1 Consolidated Fraud Risk Register — Power Sector

#	Fraud Scheme	Entity Type	Area	How It Works	Detection Procedure
1	Coal weighbridge software manipulation	Thermal GENCO	Fuel	Weighbridge database table edited; net weights reduced; GENCO pays for coal not received	Software audit trail; DB change log; privileged access review; spot weighments at independent scale
2	GCV over-certification at loading point	Thermal GENCO	Fuel	Third-party sampler colludes with coal company; GCV certified higher than actual; GENCO overpays	Independent re-sampling by GENCO; comparison loading point vs plant GCV; CIMFR verification
3	PAF inflation — outage misclassification	Thermal GENCO	Operations	Forced outages classified as grid constraint; PAF inflated; full capacity charges claimed	SLDC/RLDC instruction cross-verification; SCADA data comparison; maintenance work order timing
4	Coal stacking fraud	Thermal GENCO	Fuel	Less coal received than recorded; stack height manipulated or hollow stacking	Drone/GPS volumetric survey; coal receipt records; bulk density independent measurement
5	Oil diversion at plant	Thermal GENCO	Operations	Fuel oil drawn for non-plant use; records show oil consumed in boiler	Tank dip reconciliation; oil flow meter; CCTV at oil pump house
6	Ash sale suppression	Thermal GENCO	Environmental	Fly ash sold but revenue not fully accounted; off-book cash	Physical ash movement CCTV; cement company confirmation; third-party weighbridge; material balance

#	Fraud Scheme	Entity Type	Area	How It Works	Detection Procedure
7	Contractor bill inflation — MB fraud	All capital works	Procurement	MB quantities overstated; certifying engineer compensated; excess payment to contractor	Surprise physical measurement; MB entry vs field conditions; comparison with Schedule of Rates
8	Split purchase orders	All entities	Procurement	Single requirement split into multiple POs below DFP threshold to avoid higher approval	Data analytics: vendor-period-item aggregation within 30 days vs DFP threshold
9	Advance payment misappropriation	All entities	Procurement	Mobilisation advance taken; UC submitted but resources not mobilised; contractor disappears	Physical verification of resources claimed in UC; advance recovery tracking; PG adequacy
10	OB removal over-reporting	Integrated GENCO (mine)	Mine	MDO claims higher OB BCM than actually moved; paid per BCM	GPS/drone survey of OB dump; compare with face survey; strip ratio analysis
11	Coal production over-reporting at mine	Integrated GENCO (mine)	Mine	Production records inflated to inflate MDO payment or coal transfer	Drone survey; weighbridge vs dispatch vs stock; HEMM productivity cross-check
12	Explosives diversion at mine	Integrated GENCO (mine)	Mine	Explosives drawn from magazine; portion diverted; blasting records falsified	Three-way reconciliation: magazine receipts vs issue vs blasting records; PESO licence vs stock
13	AT&C loss understatement — agricultural	DISCOM	Operations	Agricultural consumption estimate inflated; AT&C loss understated; RDSS grant claimed	Field survey of pump HP; energy balance cross-check; feeder-level analysis
14	Cash collection not deposited	DISCOM	Finance	Consumer pays cash; cashier issues receipt but does not deposit full amount	Daily cash vs bank deposit slip; surprise cash count; system receipt vs bank credit
15	Smart meter data manipulation in HES	DISCOM	IT	HES database altered to show lower consumption; billing reduced	HES audit trail; meter-side OBIS data vs HES; database access log review

#	Fraud Scheme	Entity Type	Area	How It Works	Detection Procedure
16	Exchange trading beyond position limits	Exchange participant	Trading	Trader exceeds exchange-specified position limits; speculative position; losses concealed	Independent pull of exchange settlement statements; compare with position limits
17	REC double-claiming	RE GENCO	Regulatory	Same generation used for REC and G-DAM RE-attributed sale	Cross-verify REC application data with G-DAM sales by technology and period
18	GHG inventory under-reporting	All (CCTS)	ESG	Fuel consumption intentionally understated; lower emissions shown	Reconcile GHG fuel data with FPA; cost audit coal consumption; any divergence above 5%
19	CSR expenditure inflation	All (CSR)	ESG/Social	CSR claimed but programmes not implemented; UC from implementing agency false	Field verification; direct beneficiary contact; bank account verification; site inspection
20	ERP fictitious vendor — payment fraud	All entities	IT	Fictitious vendor in master; PO raised; payment made to fraudster's account	Vendor master change log; new vendor verification; bank account call-back; SoD check
21	OT insider threat — relay setting manipulation	TRANSCO; GENCO	OT	Malicious insider changes relay settings; equipment damaged; outage caused	Relay configuration change log; compare with approved settings; any undocumented change
22	Insurance claim inflation	All entities	Insurance	Insured event; loss deliberately inflated; excess recovery shared	Independent technical assessment before cleanup; compare with asset register; independent quotes
23	Force majeure fabrication	GENCO; TRANSCO	Contracts	FM event not genuine or exaggerated; LD avoided; deemed generation claimed	IMD records; NDRF/SDRF deployment; satellite imagery; media at time of event

#	Fraud Scheme	Entity Type	Area	How It Works	Detection Procedure
24	Ghost employee — payroll	All entities	HR	Fictitious employees on payroll; salary to fraudster's account	HR vs payroll headcount reconciliation; bank account uniqueness; biometric vs payroll
25	Whistleblower complaint suppression	All entities	Governance	Genuine complaint received; closed without investigation under management pressure	Complaint register access by Audit Committee; any complaint closed within 24 hours without investigation

APPENDIX 11

COMMON FINDINGS REFERENCE — CAG, CERC/SERC AND DGMS

Reference: Sections 14.10 and 14.11

A11.1 Thermal GENCO — Most Common CAG Findings

Finding	Typical Financial Impact	Pre-Emption Audit Procedure	Key Evidence
GCV dispute not filed within 45 days	Rs. 2-15 crore/year	Sampling report date vs dispute filing date — every month	Third-party sampling reports; dispute correspondence
ACQ shortfall penalty not raised	Rs. 1-10 crore/FSA period	Monthly ACQ tracking; penalty computation; billing verification	Coal supply statements; FSA; penalty bills
Coal stock book vs physical discrepancy	Rs. 5-50 crore	Surprise volumetric survey using drone/GPS	Survey report; bulk density test; weighbridge records
Weighbridge fraud	Rs. 10-100+ crore	Statistical analysis of truck frequency and net weight distribution; CCTV; audit trail	Weighbridge log; CCTV footage; spot weighments
PAF manipulation — outage misclassification	Rs. 5-30 crore/year	SLDC/RLDC instruction cross-verification for all grid constraint entries	SLDC records; outage log; SCADA historian
FPA under-billing — GCV inconsistency	Rs. 2-20 crore/year	FPA GCV vs sampling certificate — every month	FPA computation sheet; sampling certificates
MB fraud in capital works	Rs. 1-50 crore/contract	Surprise physical measurement against MB; bulk entry check	MB; site measurements; construction photos
Split purchase orders	Process integrity	Data analytics: vendor-period-item aggregation vs DFP threshold	PO register; DFP document
CEMS data manipulation	Regulatory; reputational	OCEMS portal data vs stack test; gap analysis; batch upload detection	OCEMS data; stack test reports; calibration records
Ash utilisation overstatement	Rs. 0.5-5 crore	Material balance: coal consumed × ash% vs Fly ash utilisation report (CPCB portal) vs physical pond level	Fly ash utilisation report (CPCB portal); coal records; ash pond survey; buyer confirmation

A11.2 DISCOM — Most Common CAG Findings

Finding	Typical Financial Impact	Pre-Emption Audit Procedure	Key Evidence

Finding	Typical Financial Impact	Pre-Emption Audit Procedure	Key Evidence
AT&C loss understatement — agricultural estimate	Rs. 20-200 crore impact on RDSS	Field survey of pump HP; energy balance per feeder	HP survey records; feeder energy data; DT meter readings
RA without SERC approval	Rs. 10-100 crore recoverability risk	Verify SERC order for every RA balance	SERC orders; RA ledger; balance sheet note
Power purchase imprudence	Rs. 5-50 crore SERC disallowance	Reconstruct merit order; compare actual scheduling	Merit order; scheduling data; exchange price data
RDSS UC misrepresentation	Rs. 10-50 crore grant at risk	HES communication report vs UC claimed installation	HES portal; installation records; field verification
Collection efficiency misrepresentation	Revenue misstatement	Remove advances from numerator; check write-offs	Billing records; receipt records; write-off approvals
Electricity duty non-remittance	Rs. 1-20 crore working capital misuse	Monthly ED collected vs remitted	ED billing records; treasury payment receipts

A11.3 CERC/SERC — Most Common Disallowances

Disallowance Category	Typical Impact	Pre-Emption Procedure	Documentation Required
O&M above normative	Rs. 5-30 crore/tariff period	Compute O&M/MW; identify excess categories; build justification file	Specific expense records; engineering justification
Capital cost above prudent estimate	Rs. 20-200 crore per project	Running comparison with DPR estimate; VO CERC prudency assessment	DPR; VO records; market rate comparisons
IDC inflated	Rs. 5-50 crore per project	Pre-filing IDC computation; delay attribution analysis	Construction milestone records; expenditure dates
Items not related to power generation	Rs. 1-20 crore per petition	Pre-filing capital cost segregation review	Asset register with function classification
SHR/APC/SOC above normative without documentation	Rs. 2-15 crore per year	Monthly contemporaneous root cause documentation	Boiler test reports; equipment records; GCV dispute records

Disallowance Category	Typical Impact	Pre-Emption Procedure	Documentation Required
FGD bond forfeiture risk where FGD remains required	Rs. 25-100 crore per unit	FGD progress monitoring; CERC timeline management	FGD progress reports; contractor milestone records

A11.4 DGMS — Most Common Observations

Observation	Risk Level	Pre-Emption Procedure	Verification Evidence
Mine Manager certificate gap	Critical — mine closure risk	Mine Manager succession register; quarterly review	Certificate copy; expiry date; successor identified
SCSR condition or expiry	Critical — safety	Monthly SCSR inspection; expiry date register	SCSR inspection register; expiry dates
CH_4 monitoring gap	Critical — explosion risk	Daily atmospheric monitoring records; instrument calibration	Monitoring log; calibration records
Accident under-reporting	Critical — prosecution	Cross-reference with hospital; ESI records; BOCW	Accident register; hospital records; police records
Explosives discrepancy	Critical — security risk	Monthly three-way reconciliation	Magazine register; issue register; blasting records
Statutory appointment vacancy	Critical	Appointment register; certificate validity tracking	Appointment orders; certificate numbers and validity

APPENDIX 12

FINANCIAL IMPACT CALCULATION TEMPLATES

Reference: All entity audit chapters; Section 2.10

A12.1 Thermal GENCO Formulas

SHR Deviation:

Excess coal = (Actual SHR − Normative SHR) × Gross generation kWh ÷ 1,000,000 ÷ GCV Kcal/kg × 1,000 = Excess coal tonnes
Financial impact = Excess coal × Weighted average coal price per tonne

PAF Below Normative:

Revenue loss = Annual Fixed Charges × (Normative PAF − Actual PAF) ÷ Normative PAF

Coal Stock Below CEA Norm:

Required stock (tonnes) = CEA norm (days, for the plant's distance from mine) × Normative daily consumption (Section 8.2.3, Step 2)
Exposure = (Required stock − Actual physical stock) tonnes × Weighted average coal price per tonne

GCV Shortfall:

Overpayment = (FSA GCV − Actual GCV) ÷ FSA GCV × Total coal received tonnes × Coal price per tonne

FPA Under-billing:

Monthly shortfall = Correct FPA amount − Billed FPA amount
Annual total = Sum of monthly shortfalls

ACQ Penalty Not Raised:

Penalty = (Trigger-level quantity, e.g. 75% of ACQ for the assessment period − Actual supply) × compensation rate

SOC Above Normative:

Excess oil KL = (Actual SOC − 0.30) ml/kWh × Gross generation kWh ÷ 1,000,000
Financial impact = Excess oil KL × Oil price per KL

APC Above Normative:

Excess units = (Actual APC% − Normative APC%) ÷ 100 × Gross generation kWh
Financial impact = Excess units × Variable charge per kWh

MSME 37(2)(g) Disallowance:

Tax impact = Total MSME dues outstanding beyond 45 days × Corporate tax rate

A12.2 Mine Audit Formulas

Production Shortfall — Incremental Cost:

Incremental cost = (Approved plan production − Actual production) tonnes × (CIL FSA coal cost − Mine transfer price) per tonne

OB Over-reporting:

Excess payment = (MDO-claimed BCM − Independently surveyed BCM) × MDO rate per BCM

Royalty Delay — Interest:

Interest = Outstanding royalty × State Mining Rules interest rate × Days delayed ÷ 365

DMF Shortfall:

Shortfall = Royalty amount × Applicable rate (30% or 10%) − Amount deposited

A12.3 RE GENCO Formulas

Solar CUF Below PPA Guarantee:

Revenue shortfall = (Guaranteed CUF% − Actual CUF%) ÷ 100 × Installed capacity kW × 8,760 hours × PPA tariff per kWh

REC Time-Barred:

Revenue lost = Time-barred generation units × prevailing REC market price

BESS RTE Below Guarantee:

Energy loss = (Guaranteed RTE% − Actual RTE%) ÷ 100 × Energy cycled kWh × Applicable tariff per kWh

Deemed Generation Claim Not Filed:

Unclaimed amount = Curtailed MW × Curtailed hours × Applicable deemed generation tariff

A12.4 DISCOM Formulas

AT&C Loss Above SERC Norm:

Revenue leakage = (Actual AT&C% − SERC norm AT&C%) ÷ 100 × Input energy MWh × Average realisation per MWh

Late Payment Surcharge (LPS) to GENCO:

LPS = Overdue amount × applicable rate under the LPS Rules 2022 (SBI one-year MCLR + 5% for the first month, rising 0.5% a month up to 3% above base) × days overdue ÷ 365

RPO Shortfall Penalty:

Penalty = SERC prescribed penalty per unit × Shortfall units

Collection Efficiency Shortfall:

Uncollected = (Target CE% − Actual CE%) ÷ 100 × Amount billed

Regulatory Asset Without SERC Approval:

Opportunity cost per year = Unapproved RA amount × Carrying cost rate

A12.5 Procurement and Capital Works Formulas

Capital Works Cost Overrun:

Overrun = Actual cost − Approved cost. The overrun portion is at risk of CERC/SERC prudency disallowance.

Liquidated Damages Not Recovered:

LD = LD rate per week × Weeks delayed × Contract value

Advance Not Recovered:

Interest loss = Outstanding advance × Advance interest rate per contract × Days beyond recovery schedule ÷ 365

MB Quantity Excess:

Excess payment = (MB quantity − Physical verified quantity) × Contract rate

VO at Inflated Rate:

Excess paid = (VO rate − Comparable rate) × VO quantity

A12.6 Taxation Formulas

TDS Default Interest:

Interest = TDS amount × 1.5% per month × Months from deduction to payment

GST ITC Over-Claim — Interest:

Interest = Excess ITC × 18% per annum × Days from return date to correction date ÷ 365

Transfer Pricing Adjustment:

TP adjustment = (Arm's length price − Actual price) × Transaction volume
Penalty — 2% of transaction value for documentation or reporting failures; penalty on under-reported income is separate

MSME Delayed Payment — Interest (MSMED Act 2006, Section 16):

Interest = Outstanding MSME payable × 3 × RBI Bank Rate × Days overdue ÷ 365, compounded at monthly rests. This is separate from the tax disallowance under Section 37(2)(g).

A12.7 ESG and Crisis Management Formulas

CSR Shortfall:

Unspent = 2% of average net profit (preceding 3 years) − CSR spent. Where the unspent amount is not transferred as required under Section 135(5)/(6), penalty = lower of twice the amount or Rs. 1 crore (company); lower of one-tenth of the amount or Rs. 2 lakh (each officer in default)

Ransomware Attack — Operational Impact:

Impact = Generating capacity MW × Hours offline × Capacity charge Rs./MW-hour + Recovery cost + Ransom if paid

Insurance Claim Not Notified:

Exposure = Total claim value × Repudiation probability

APPENDIX 13

INTERNAL AUDIT CHARTER — MODEL

Reference: Sections 1.7 and 2.12

INTERNAL AUDIT CHARTER

[ENTITY NAME]

Approved by the Board of Directors at its meeting held on [Date]
To be reviewed at least once every three years

Article 1 — Purpose and Authority

1.1 The Internal Audit Department (IAD) of [Entity Name] is established by the Board of Directors in accordance with Section 138 of the Companies Act 2013, Rule 13 of the Companies (Accounts) Rules 2014, DPE guidelines on Corporate Governance for Central Public Sector Enterprises (for CPSUs), SEBI LODR Regulation 18 read with Schedule II Part C (for listed entities), Global Internal Audit Standards™ (2024 Edition) and ICMAI Internal Audit and Assurance Standards (IAAS).

1.2 The purpose of the IAD is to provide independent, objective assurance and consulting services designed to add value and improve the operations of [Entity Name]. The IAD assists the organisation to accomplish its objectives by bringing a systematic, disciplined approach to evaluate and improve the effectiveness of risk management, control, and governance processes.

1.3 The Chief Internal Auditor (CIA) has the authority to access all functions, records, property and personnel of the organisation necessary to accomplish audit work. The CIA shall have direct and unrestricted access to the Audit Committee and its Chairman.

Article 2 — Independence and Objectivity

2.1 The IAD shall be independent of the activities it audits. The CIA reports functionally to the Audit Committee and administratively to the Chairman and Managing Director (or equivalent).

2.2 Internal auditors shall have no operational authority over any of the activities they audit, shall not be assigned operational responsibilities; and shall not implement audit recommendations.

2.3 Internal auditors shall disclose any impairment to their independence or objectivity including actual, potential or apparent conflicts of interest to the CIA before undertaking any assignment. The CIA shall disclose any such impairment to the Audit Committee.

2.4 Rotation policy: Internal auditors assigned to any specific entity or plant shall be rotated at intervals not exceeding [3 years]. This prevents familiarity risk.

2.5 For CPSUs: compliance with CVC guidelines on independence and objectivity of internal audit is mandatory in addition to the above.

Article 3 — Scope of Internal Audit

3.1 The scope of the IAD encompasses all operations, functions, systems and locations of [Entity Name] and its subsidiaries (where the IAD has been designated by the respective Board). The scope includes but is not limited to:

(a) Adequacy and effectiveness of the internal control framework across all functional areas;

(b) Reliability and integrity of financial and operational information;
(c) Compliance with laws; regulations; CERC/SERC orders; DGMS regulations; environmental standards; and internal policies;
(d) Economic, efficient, and effective use of resources;
(e) Safeguarding of assets;
(f) Risk management processes — including the Risk-Based Internal Audit (RBIA) framework;
(g) Governance processes — including ethics; independence; accountability; and transparency;
(h) ESG and sustainability reporting data integrity;
(i) IT systems; cybersecurity; and OT/SCADA security in coordination with the CISO;
(j) Fraud risk assessment and investigation support (in coordination with Vigilance).

3.2 The IAD shall cover all units; plants; mines; and offices of [Entity Name] in accordance with the Annual Audit Plan approved by the Audit Committee.

Article 4 — Professional Standards

4.1 The IAD shall conduct its work in accordance with: ICMAI Internal Audit and Assurance Standards (IAAS), Global Internal Audit Standards™ (2024 Edition), and applicable provisions of the Companies Act 2013 and Rules thereunder.

4.2 Internal auditors shall maintain professional competence through continuing professional education. The CIA shall ensure that the team collectively possesses the skills and knowledge required to audit the power sector including regulatory knowledge, IT audit, OT security, ESG and forensic accounting.

Article 5 — Responsibilities of the CIA

5.1 The CIA is responsible for:

(a) Development and maintenance of a risk-based Annual Audit Plan for approval by the Audit Committee;
(b) Overseeing the execution of the Annual Audit Plan;
(c) Reporting significant findings and their status to the Audit Committee quarterly;
(d) Maintaining the Master Audit Findings Register (MAFR) covering findings from all oversight bodies;
(e) Coordinating with CAG/AG; CERC/SERC; and other external oversight bodies;
(f) Quality assurance of the IAD's work;
(g) Development of the IAD team.

Article 6 — Reporting

6.1 The CIA shall report to the Audit Committee: quarterly status of the Annual Audit Plan, significant findings and their financial impact, status of open audit observations, multi-audit universe management status, and emerging risks.

6.2 The CIA shall report to the Chairman and Managing Director: audit findings requiring immediate management action, any serious irregularity identified, any matter where management has not taken adequate corrective action on a significant audit finding.

6.3 For Serious Irregularities — the CIA shall issue a Flash Report to the Audit Committee Chairman within 24 hours of identification, without waiting for the next scheduled meeting.

6.4 The CIA shall have the right to place any matter before the Audit Committee without management's prior approval — this right shall not be curtailed or restricted by any member of management.

Article 7 — Coordination

7.1 The CIA shall coordinate with the Statutory Auditor — sharing audit plans, significant findings, and management letters — to ensure complementarity of coverage and avoid duplication.

7.2 The CIA shall coordinate with the Cost Auditor on cost records accuracy and CERC true-up data reconciliation.

7.3 The CIA shall coordinate with the CAG/AG audit party — facilitating access, providing accurate responses, and tracking compliance with CAG findings.

7.4 The CIA shall coordinate with the Vigilance Department — referring fraud allegations through the appropriate protocol while maintaining the boundary between audit and investigation.

Article 8 — Resources

8.1 The Audit Committee shall ensure that the IAD has: adequate staff with appropriate qualifications and experience for the power sector, a budget adequate for the audit plan, access to data analytics tools, access to technical specialists where needed (IT auditors, environmental experts, mining safety experts) and the ability to engage external specialists for specific assignments.

Article 9 — Review of the Charter

9.1 This Charter shall be reviewed at least once every three years by the Audit Committee and updated as necessary to reflect changes in the organisation, regulatory requirements, or professional standards. Any substantive change to the Charter requires Board approval.

Approved by the Board of Directors:
[Chairman]
[Date]

APPENDIX 14

MASTER AUDIT FINDINGS REGISTER — TEMPLATE

Reference: Sections 14.10 and 2.13

A14.1 MAFR Template Structure

The Master Audit Findings Register is maintained by the Chief Internal Auditor and updated by the 10th of each month. It is presented to the Audit Committee quarterly in summary format.

MASTER AUDIT FINDINGS REGISTER

[ENTITY NAME] —

FY 20__-__

Maintained by: Chief Internal Auditor

Last Updated: [Date]

Field	Entry
MAFR Reference	[Entity Code]/[Year]/[Source Code]/[Serial] e.g. [X]GENCO/2026/CAG-IR/003
Source	CAG-IR (Inspection Report) / CAG-AR (Audit Report Para) / CERC / SERC / IT-Dept / GST / Customs / MoEFCC / SPCB / NGT / DGMS / MoC / SEBI / CVC / IA (Internal Audit)
Date of Finding	Date of IR / order / notice / IA report
Entity/Plant	Which plant; unit; or function
Area	Fuel / Operations / Environmental / Tariff / Capital Works / Procurement / HR / Tax / IT / ESG / Safety / Mine
Nature of Finding	[One-line factual description]
Financial Amount	Rs. [X] crore (demand / disallowance / exposure / claim)
Compliance Deadline	[Date by which response or action is due]
Responsible Officer	Name; Designation
Status	Open / Response Filed / Under Appeal / Partially Complied / Complied / Closed
Action Taken to Date	[Brief description of action taken]
Next Action Required	[What needs to be done; by whom; by when]
Overlap Flag	[Any other oversight body examining same transaction — cite MAFR reference]
Provision in Books	Rs. [X] crore provisioned / Rs. [Y] crore contingent liability disclosed / Nil — reason
Escalation Flag	Red (overdue or critical) / Amber (deadline within 30 days) / Green (on track)
Closure Basis	[How resolved — paid; reversed; successfully appealed; withdrawn; corrected]
Closure Date	[Date when formally closed by CIA]

Field	Entry
Learning Loop	[IA procedure derived from this finding; applied at which other units]

A14.2 MAFR Source Codes

Code	Source
CAG-IR	CAG/AG Inspection Report Para
CAG-AR	CAG Audit Report Para (formal; presented to Parliament/Legislature)
CAG-PA	CAG Performance Audit finding
CERC	CERC tariff order disallowance or observation
SERC	SERC tariff order disallowance or observation
IT-Dept	Income Tax demand or notice
GST	GST demand; SCN or audit
CUST	Customs demand or notice
ENV	MoEFCC or SPCB show cause notice; NGT order
DGMS	DGMS inspection observation or prosecution
SEBI	SEBI LODR non-compliance; notice
CVC	CVC complaint or observation
BEE	BEE PAT observation; ESCert deficit; CCTS default
IA	Internal Audit finding
PAC/COPU	PAC or COPU direction
MoC	Ministry of Coal / CCO observation
APTEL	APTEL order (appeal outcome)

A14.3 Quarterly Audit Committee MAFR Summary Format

AUDIT COMMITTEE MEETING —[QUARTER] [YEAR]

MULTI-AUDIT STATUS SUMMARY

Source	New This Quarter	Resolved This Quarter	Total Open	Financial Exposure (Rs. crore)	Oldest Open (Date)
Internal Audit					
CAG — IR Paras					
CAG — Audit Report Paras					
CERC Disallowances					
SERC Disallowances					
Income Tax Demands					
GST Demands					
Environmental SCNs/NGT					
DGMS (Safety)					

Source	New This Quarter	Resolved This Quarter	Total Open	Financial Exposure (Rs. crore)	Oldest Open (Date)
MoC (Mine)					
BEE (PAT/CCTS)					
CVC					
TOTAL					

Matters requiring Audit Committee direction this quarter:

[List of matters requiring AC-level decision or escalation]

Matters resolved since last Audit Committee meeting:

[List of matters closed]

Learning Loop — Procedures Added This Quarter:

[List of new IA procedures derived from external audit findings]

APPENDIX 15

INTERNAL AUDIT REPORT FORMAT — POWER SECTOR

Reference: Section 2.13.5

INTERNAL AUDIT REPORT FORMAT

[ENTITY NAME] — [AUDIT AREA/UNIT] — [AUDIT PERIOD]

COVER PAGE

Entity: [Name]

Unit/Location: [Plant/Mine/Circle/Division]

Audit Area: [e.g. Fuel Management / Capital Works / AT&C Loss / Environmental Compliance]

Audit Period: [From date] to [To date]

Report Reference: [IA Report Number per numbering convention]

Date of Report: [Date]

Issued By: Chief Internal Auditor / Senior Internal Auditor

Presented To: Audit Committee / Chairman and Managing Director

SECTION 1 — EXECUTIVE SUMMARY

Para Category	**Number of Paras**	**Financial Impact (Rs. crore)**
Serious Irregularities		
Major Findings		
Minor Findings		
Observations / Advisory		
Total		

Top Three Findings by Significance:

1. [Para reference] — [One-line summary] — Rs. [X] crore
2. [Para reference] — [One-line summary] — Rs. [X] crore
3. [Para reference] — [One-line summary] — Rs. [X] crore

Overall Internal Control Assessment:

☐ Satisfactory ☐ Needs Improvement ☐ Unsatisfactory

Reason for Assessment: [Brief narrative — 2-3 sentences]

SECTION 2 — SCOPE AND METHODOLOGY

Period covered; documents reviewed; systems accessed; data analytics applied; physical verifications conducted; meetings held with management; limitations if any.

SECTION 3 — REGULATORY COMPLIANCE STATUS

Compliance Area	Standard/Norm	Status	Finding Reference
PAF vs CERC normative	85%	[Compliant/ Non-compliant]	[Para ref if any]
SHR vs CERC normative	[Applicable norm]	[Compliant/Non-compliant]	
CEMS data gaps	Below 5%	[Compliant/Non-compliant]	
Ash utilisation	100%	[Compliant/Non-compliant]	
FGD compliance	As per category	[Compliant/Non-compliant]	
EC conditions	All conditions	[Compliant/Non-compliant]	
[Other applicable]			

SECTION 4 — OPERATIONAL PERFORMANCE DASHBOARD

KPI	CERC/SERC Norm	Actual	Variance
PAF (%)	85%		
SHR (Kcal/kWh)	[Norm]		
APC (%)	[Norm]		
SOC (ml/kWh)	0.30		
Coal stock (days)	[CEA norm for the plant]		
AT&C loss (%) [DISCOM]	[SERC norm]		
Collection efficiency [DISCOM]	[Target]		

SECTION 5 — DETAILED AUDIT PARAS

[Each para in full CCCCE format as follows:]

Para Reference: [Entity Code]/[Plant]/[Financial Year]/[Area Code]/[Serial]

Category: [Serious Irregularity / Major Finding / Minor Finding / Observation]

Area: [Fuel / Operations / Environmental / Procurement / etc.]

Criteria: [The applicable standard; regulation; norm; contract term; or management policy — what should be]

Condition: [What was found — factual; evidence-based; no opinion]

Cause: [Why it happened — root cause; systemic analysis]

Consequence: [Financial impact — quantified; regulatory risk; operational risk; reputational impact]

Recommendation: [Specific; actionable; time-bound corrective action]

Management Response: [Verbatim or summarised management response — to be filled after draft report circulation]

Auditor's Comment on Response: [Whether response is adequate; any remaining concern; verification required]

Target Date: [Management-committed date for compliance]

[Additional paras follow in same format]

SECTION 6 — ESG AND SUSTAINABILITY OBSERVATIONS *(for listed entities or where applicable)*

[GHG data accuracy; water compliance; BRSR consistency; social compliance observations — paras in CCCCE format]

SECTION 7 — IT AND CYBERSECURITY OBSERVATIONS

[SoD conflicts; access management gaps; OT security; CERT-In compliance — paras in CCCCE format]

SECTION 8 — FOLLOW-UP STATUS — PREVIOUS PERIOD OPEN PARAS

Para Reference	Period	Category	Finding Summary	Financial Amount	Status	Verification Basis
					Open/Complied/Partially	

SECTION 9 — PARA STATUS SUMMARY TABLE

Para Ref	Category	Finding Summary	Financial Impact (Rs.)	Management Response	Target Date	Escalation Flag

SECTION 10 — FINANCIAL IMPACT OF INTERNAL AUDIT

Type	Amount (Rs. crore)
Recoveries made or initiated based on audit findings	
Penalty bills raised on coal companies based on audit	
Revenue protected — disputes filed; claims raised	
Excess expenditure avoided through pre-audit checks	
Regulatory penalties prevented through pre-petition review	
Total Value Added by Internal Audit	

SECTION 11 — CONCLUSION

[2-3 paragraph overall conclusion on control environment; key risks; management's commitment to remediation; any matter requiring Board-level attention]

ANNEXURES

Annexure A: Financial impact computation for significant paras

Annexure B: Data analytics output supporting findings

Annexure C: Physical verification photographs and GPS coordinates

Annexure D: List of documents examined

[Signature and designation of CIA or Senior Internal Auditor issuing the report]
[Date]