DG Technical Requirements Benchmark

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What we will cover

1 **Why & where —** technical requirements in the regulatory-to-utility stack; safety and grid integrity

2 **The benchmark —** anonymised case studies of existing workflows and their inefficiencies

3 **The template —** our best-practice DG application flow and connection criteria

Why technical requirements matter — and where they sit

CHAPTER 1

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Where technical requirements sit

National energy policy & Electricity Act
Mandate to connect DG; legal basis for generation, licensing and exemptions

Regulator: DG regulations
Rules of the game — access, tariffs, licensing/registration thresholds

Utility DG Technical Requirements
What the system must do + the application & commissioning process

THIS SESSION

DG Specifications, forms, commissioning & checks
Inverter certification, SLDs, CoC, connection criteria, control checks

Why it is critical (1)

- Anti-islanding
- Fire & shut-off
- Certified equipment
- Competent install
- Voltage rise
- Power quality
- Hosting capacity exceedance
- Frequency variations

Why it is critical (2): A working market

Certainty

Clear, proportionate rules let installers and investors plan and price.

Fair access

Non-discriminatory, transparent access prevents arbitrary refusals.

Fewer illegal systems

A workable legal path beats unauthorised, unsafe connections.

Revenue protection

Correct metering and tariffs stop losses from meters running backwards.

DG Workflows as they exists today

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Case study: Country A

The rules as they stand

1. Regulator licenses all DG above 1 MW. Regulator does technical checks and informs the utility afterward
2. Below 1 MW: no licence required, except for systems exporting to the grid
3. Full application process, including technical checks, only DG who wish to enter into a net metering agreement
4. Full application process only for net-metering systems

Discussion: What are some of the pitfalls?

? What does it mean for systems below 1 MW that connect with no review?

? Should a commercial choice — net metering — decide whether a system is checked?

? Who carries the risk when the requirements are not enforced?

Case study: Country B

The process as it stands

1. All DG applications are submitted to the Ministry of Energy.
2. The Ministry transmits each application to the Regulator for a decision
3. The Regulator forwards it to the Utility for the technical checks and then send back to regulator for final decision
4. Once system is installed, regulator does the technical inspection against the wiring standard etc.
5. Utility then does the commissioning test before the system is allowed to connect

Discussion: What are some of the pitfalls?

? What does a multi-stage chain mean for prospective DG systems?

? Does routing every application through the Ministry add value, or mostly delay?

? Who is accountable when hand-offs between agencies stall?

Case study: Country C

The process as it stands

1. Single application route for all systems
2. Every application triggers a detailed grid study
3. Technical assessment
4. Negotiate connection terms
5. Commission and connect

Discussion: What are some of the pitfalls?

? What does it mean when even a small system must complete a full grid study?

? Where does the process bottleneck when every application needs specialist review?

? Should a low-risk DG system wait in the same queue as a large plant?

? Can a one-size-fits-all process scale with rising demand?

Case study: Country D

The rules as they stand

1. Eligible systems size 20–100 kW. No limits linked to the customer’s supply or contracted capacity with the utility
2. Utility does all technical checks
3. Energy netted kWh-for-kWh (net metering) at the end-user tariff
4. 5-year settlement cycle; any excess credit then written off

Discussion: What are some of the pitfalls?

? Why are smaller residential customers (<20 kW) excluded?

? What is the implication of the omission of the individual system limits

? How easy is it implement a customer’s reconciliation system over a 5-year billing cycle?

Common inefficiencies across the existing workflows

Lack of proportionality

Same burden for the smallest and largest systems

Long / undefined timeframes

Slow or open-ended response times deter applicants

Excessive documentation

Full engineering packages for low-risk systems

Fragmentation

Multiple bodies, sequential approvals, no single owner

Loose technical checks

Basic checks often limited to equipment performance during commissioning

No simplified fast track

Every application treated as a major grid study

Lack of clarity on qualifications requirements

Lack of clarity on sign-off required for the installation and the commissioning; no industry accreditations

No pre-approved equipment list

Every inverter/meter is reviewed from scratch instead of drawing on a type-approved list.

Manual, paper-based intake

No online portal or status tracking

The best-practice template

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Five principles behind the template

1	**Risk-proportionate**	Tier obligations by size and export — light touch for small, low-risk systems.
2	**Simplified connection criteria**	Simplified grid impact assessments clear most systems without a full study.
3	**Defined timeframes**	A published response time the utility commits to (e.g. 30 working days).
4	**Single, transparent window**	One owner of the process; steps and attachments known in advance.
5	**Recognised certification**	Accept relevant inverter certificates and accredited installers.

The best-practice application flow

1. **Apply** — Complete form; customer + installer details; agree T&Cs
2. **Submit** — Form + attachments: SLD and inverter certificate
3. **Approve start** — Utility assesses: simplified criteria or grid study; defined timeframe
4. **Commission** — Competent person; commissioning report, CoC, as-built
5. **Inspect** — Risk-based inspection by the utility, if necessary
6. **Connect** — Meter installed, tariff applied, generation begins

Step 1: Complete the application form

Best practice

- One standard form for all applications
- Customer + proposed installer details captured
- Signing the form = agreeing the connection T&Cs
- Downloadable online and at offices

Step 2: Submit form and attachments

Best practice

- Single-line diagram above a sensible size threshold
- Recognised inverter certificate
- Proportionate attachments
- External approvals run in parallel, not as a pre-gate

Step 3: Assessment and approval to commence

Best practice

- Published, committed timeframe (e.g. 30 working days)
- Simplified connection criteria clear most systems fast
- Grid study only when thresholds are exceeded
- Written notification of outcome and any further steps

Step 4: Commissioning and documentation

Best practice

- Tiered sign-off: accredited installer or professional engineer up to a threshold
- Commissioning report + electrical CoC always
- Final as-built SLD submitted
- Utility given notice; may attend commissioning

Step 5: Inspection

Best practice

- Risk-based: inspect where warranted, not by default
- Clear criteria for when inspection is triggered
- Unlikely for small residential systems
- A consistent national approach

Step 6: Approval to connect, metering and tariff

Best practice

- Bi-directional meter installed or verified
- No spinning-disc meters allowed to run backwards
- DG tariff applied on connection
- Written approval to connect; generation may begin

Cross-cutting: installer qualifications

Best practice

- **Third-party accreditation —** of installers, recognised by the utility.
- **Tiered competence —** matched to system size and complexity.
- **Named installer —** on the form, linked to the accreditation / licenced register.
- **Clear consequences —** for non-compliant or illegal installations.

Thank you for your attention

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