Recommended Practice for the Application of Electrical Submersible Cable Systems

API RECOMMENDED PRACTICE 11S5
SECOND EDITION, APRIL 2008

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Upstream Segment

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Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, D.C. 20005, standards@api.org.

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Recommended Practice for the Application of Electrical Submersible Cable Systems

1 Scope

This document covers the application (size and configuration) of electrical submersible cable systems by manufacturers, vendors, or users.

2 Normative References

This recommended practice includes by reference, either in total or in part, other standards and recommended practices listed below. The latest edition of these standards and recommended practices should be used unless otherwise noted:

API RP 11S6, *Recommended Practice for Testing of Electric Submersible Pump Cable Systems*

ASTM A90[1], *Standard Test Methods for Weight (Mass) of Coating on Iron and Steel Articles with Zinc or Zinc-Alloy Coatings*

ASTM A459, *Standard Specification for Zinc-Coated Flat Steel Armoring Tape*

ASTM B3, *Standard Specification for Soft or Annealed Copper Wire*

ASTM B8, *Standard Specification for Concentric-Lay-Stranded Copper Conductors, Hard, Medium-Hard, or Soft*

ASTM B33, *Standard Specification for Tinned Soft or Annealed Copper Wire for Electrical Purposes*

IEEE 1018[2], *Recommended Practice for Specifying Electric Submersible Pump CableEthylene-Propylene Rubber Insulation*

IEEE 1019, *Recommended Practice for Specifying Electric Submersible Pump CablePolypropylene Insulation*

NEMA[3] WC-Code

NFPA 70[4], *National Electric Manufacturers Association—High Performance Wire and Cable Section*

3 Terms and Definitions

3.1 General

3.1.1
american wire gauge
AWG
Standard wire gauge systems used for nonferrous electrically conducting wires where increasing gauge number gives decreasing wire diameters.

3.1.2
ampacity
The current, in amperes, that a conductor can carry continuously under the conditions of use without exceeding the temperature rating of the cable.

[1]ASTM International, 100 Bar Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.
[2]Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, New Jersey 08854, www.ieee.org.
[3]National Electrical Manufacturers Association, 1300 North 17th Street, Suite 1752, Rosslyn, Virginia 22209, www.nema.org.
[4]National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.

3.1.3
antioxidants
Materials added to polymer compounds used to prevent degradation (oxidation) in rubber or plastic by retarding hardening and embrittlement.

3.1.4
compound
A mechanical blend of base polymer with other ingredients added to obtain the desired properties that are usually proprietary formulations varying between each manufacturer and that may affect the cable performance.

3.1.5
corrosion
The destruction of the surface of a metal by oxidation that can be initiated by the action of chemicals alone or in combination with well fluids.

NOTE Galvanic corrosion results from an electrochemical reaction in which an electric current flows between two dissimilar metals in a conductive medium, such as salt water.

3.1.6
cross linked polyethylene
XLPE
A polyethylene modified through a chemical reaction, which becomes permanently shaped when cured.

3.1.7
cure
The process of changing the physical characteristics of raw rubber during the manufacturing of a cable that requires a curing agent, heat, and pressure to produce a suitable insulation or jacketing material.

NOTE Vulcanizing and cross-linking are forms of curing.

3.1.8
dielectric strength
The maximum electrical potential gradient that a material can withstand without rupture, usually specified in volts per millimeter (or mils) of thickness.

NOTE This is also referred to as electric strength.

3.1.9
ethylene chlorotetrafluoroethylene
ECTFE
A chlorofluorinated thermoplastic copolymer composed of ethylene and chlorotetrafluroethylene belonging to the group of plastic materials known as fluoropolymers, that is chemically inert and a good low voltage electrical insulator.

3.1.10
elastomer
A rubber-like material that can stretch under low stress and return to its original shape when the stress is removed.

3.1.11
electrical insulation resistance
The resistance which varies between compounds and cable geometry of the insulation to the radial flow of direct current through the insulation.

NOTE A measure of performance is balanced values of insulation resistance or leakage current for each phase.

The formula to measure insulation resistance (IR) is:

$$\mathrm{IR} = \frac{E}{I}$$

where

IR is megohms at 60 °F;

E is the voltage applied between the conductor and ground in volts;

I is the DC leakage current in microamps.

3.1.12
ethylene propylene diene monomer
EPDM
A polymer composed of ethylene, propylene, and diene units that can be cured with a sulfur or peroxide.

3.1.13
ethylene propylene monomer
EPM
A polymer composed of ethylene and propylene units that must be cured with a peroxide-curing agent resulting in useful properties that are similar to EPDM.

3.1.14
ethylene propylene rubber
EPR
A term used to describe either EPDM or EPM.

3.1.15
ethylene tetrafluoroethylene
ETFE
A fluorinated thermoplastic copolymer composed of ethylene and tetrafluoroethylene belonging to the group of plastic materials known as fluoropolymers, that is chemically inert and a good low voltage electrical insulator.

3.1.16
fillers, compound
Materials added to compounds to enhance various properties such as mechanical strength, moisture resistance, and electrical characteristics.

3.1.17
fillers, physical
Materials used to fill interstices in cable construction, such as rubber and polypropylene.

3.1.18
fluorinated ethylene propylene
FEP
A thermoplastic fluorinated ethylene propylene copolymer belonging to the group of plastic materials known as fluoropolymers, that is chemically inert and a good low voltage electrical insulator.

3.1.19
hoop strength
A measure of the tangential resistance to elongation.

NOTE Internal gas pressure pushes in a radial direction creating a tendency for the surface of the insulation and jacket to elongate and rupture tangentially which the hoop strength resists, aided by additional wraps applied over the round components.

3.1.20
leakage current
The current that flows across the surface or through the insulation when a DC voltage is applied defining the insulation resistance at the specified DC potential.

NOTE Regardless of the quality of the dielectric material, all materials will exhibit some leakage current.

3.1.21
monomer
A basic chemical unit that forms a polymer by chemical linking.

3.1.22
nitrile
A copolymer of butadiene and acrylonitrile monomers, also referred to as Buna N, nitrile rubber, and nitrile butadiene rubber (NBR), which varying ratios of acrylonitrile to butadiene to provide trade off between oil resistance or low temperature properties for specific applications.

3.1.23
pigtail
A length of cable that is spliced onto the main power cable.

3.1.24
plasticizers
Chemicals added to compounds to impart flexibility, workability, and stretchability.

3.1.25
polyamide
A high molecular weight polymer thermoplastic material composed of polymers that contain an amide (-COHN-) group exhibiting a modest degree of chemical inertness and has a high tensile strength.

3.1.26
polyester
A thermoplastic material made by esterification of polybasic organic acids with polyhydric acids typically used as an alternative to polyamide as a braid material over taped barriers, most commonly over fluoropolymer barrier tape materials.

3.1.27
polyethylene
PE
A thermoplastic material composed of chemically linked ethylene monomer units.

3.1.28
polyimide
A fully reacted linear polymer incorporated with the imide group in the polymer main chain.

3.1.29
polymer
A material formed by linking together monomers through a chemical reaction, consisting of a chain of repeated structural units.

NOTE Prefixes denoting one, two or three basic units are “homo,” “co,” and “ter,” respectively.

3.1.30
polyphenylene sulfide
PPS
A material that provides good high temperature and chemical resistance.

3.1.31
polypropylene
PP
A thermoplastic material composed of chemically linked propylene monomer units used in electrical grades through the incorporation of a small percent of ethylene or butene monomer to impart better low temperature properties.

3.1.32
polytetrafluoroethylene
PTFE
A fluoropolymer inert to virtually all chemicals and considered the most slippery material in existence, used as a tape in high temperature applications.

3.1.33
polyvinyl fluoride
PVF
A fluorinated thermoplastic material composed of chemically linked fluorine monomer units, belonging to the group of plastic materials known as fluoropolymers.

3.1.34
polyvinylidene fluoride
PVDF
A fluorinated thermoplastic material composed of chemically linked vinyl fluoride monomer units, belonging to the group of plastic materials known as fluoropolymers.

3.1.35
termination
The transition from a cable to a connection that provides electrical, mechanical, and environmental integrity.

3.1.36
thermoplastics
Polymeric materials that soften or flow at elevated temperatures and harden when cooled in a reversible process, such as polypropylene (PP), polyethylene (PE), polyvinyl fluoride (PVF), polyvinylidene fluoride (PVDF), and polyamides.

3.1.37
thermoset
Polymeric materials that once cured are irreversibly cross-linked and cannot be remolded, such as EPDM and nitrile rubber.

3.2 Temperature

3.2.1
ambient temperature
The temperature surrounding the cable at any point

NOTE In a downhole environment, the ambient temperature depends on many variables which include: the reservoir temperature, the heat rise from the submersible equipment, the well temperature profile, and the thermal conductivity of well liquids, foams, and gases.

3.2.2
bottom hole temperature
The static temperature at the mid point of the perforations.

3.2.3
conductor temperature
The temperature on the surface of the current carrying conductors that is a function of heat generated by current flow in the conductor, heat dissipation through the materials, and ambient temperature.

NOTE Flat cables generate additional heat from other power losses due to the non-symmetrical construction.

3.2.4
operating temperature
The conductor temperature during steady state operation.

NOTE The maximum allowable operating temperature is defined as the rated temperature.

3.2.5
rated temperature
The maximum conductor temperature at which a cable can continuously operate without causing significant material degradation.

3.3 Trade Names

The following examples in this section are provided as an example only and do not constitute an endorsement of the product by API.

3.3.1
Apical®
A polyimide, applied directly over the conductor as a primary insulation. This is a trade name of Allied Chemical.

NOTE Because Apical has no melting point, Teflon® FEP® is laminated with the polyimide to give a heat-sealable structure for fabrication purposes.

3.3.2
Kapton®
A polyimide applied directly over the conductor as a primary insulation. This is a trade name of DuPont.

NOTE Because Kapton® has no melting point, Teflon® FEP® is laminated with the polyimide to give a heat-sealable structure for fabrication purposes.

3.3.3
Kynar®
A polyvinylidene fluoride (PVDF), used as a braid and as an extrudable barrier. This is a trade name of Pennwalt.

3.3.4
Monel®
A series of stainless metal alloys, primarily composed of nickel (up to 67 %) and copper with some iron and other trace elements. This is a trade name of Special Metals Corporation.

3.3.5
Nylon
A polyamide, most commonly used in braids where operating temperatures will be below 212 °F. There are many suppliers of nylon.

3.3.6
PEEK®
polyoxy-1,4-phenylene-oxy-1,4-phenylene-carbonyl-1,4-phenylene
A polyaryletherketone which is a high temperature thermoplastic insulation widely regarded as the highest temperature rated thermoplastic material commercially available suitable for use in applications up to 570 °F, in

addition to possessing outstanding chemical resistance and electrical insulating properties. This is manufactured by Victrex PLC.

3.3.7
Ryton®
Polyphenylene sulfide (PPS) used as a multifilament braid material. It is the registered trademark of Phillips Petroleum Company.

3.3.8
Tedlar®
A polyvinyl fluoride (PVF) used as barrier tape. This is a trade name of DuPont.

3.3.9
Teflon®
The registered trademark of DuPont and refers to DuPont's family of fluoropolymers.

3.3.10
Teflon® FEP®
A fluorinated ethylene propylene (FEP) laminated with a polyimide to form a heat-sealable tape or extrudable layer. This is a trade name of DuPont.

3.3.11
Tefzel®
An ethylene tetrafluoroethylene (ETFE) used as a barrier tape or as an extrudable barrier. This is a trade name of DuPont.

3.4 Conductor Configuration and Cable Construction

3.4.1 Scope

This section includes figures pertaining to cable construction.

3.4.2 Cable can be manufactured with many configurations to make it suitable for use in most wellbore environments. A cable manufacturer should be consulted if there are concerns about the proper cable construction for unique situations (see Figure 3.1).

4 Cable Conductors

4.1 Description

Copper conductors are used to carry AC current from the surface to the motor.

For submersible pump applications, the industry has essentially standardized on conductor metric and AWG sizes listed in Table 4.1 and Table 4.2.

4.2 Applications

Cable AWG (mm^2) size and configuration are selected based on conductivity, economic considerations, and well clearance. The maximum allowable cable diameter is constrained by the clearance between the tubing and the casing. Typically a round cable design would be selected unless the clearance requires a flat cable design or a lead product be used. The minimum conductor size is determined by the required motor current and permissible voltage drop. The selected product will be based on economic comparisons made between cable sizes, taking into consideration environmental conditions and both the initial cost and the difference in operating cost due to voltage losses in the cable.

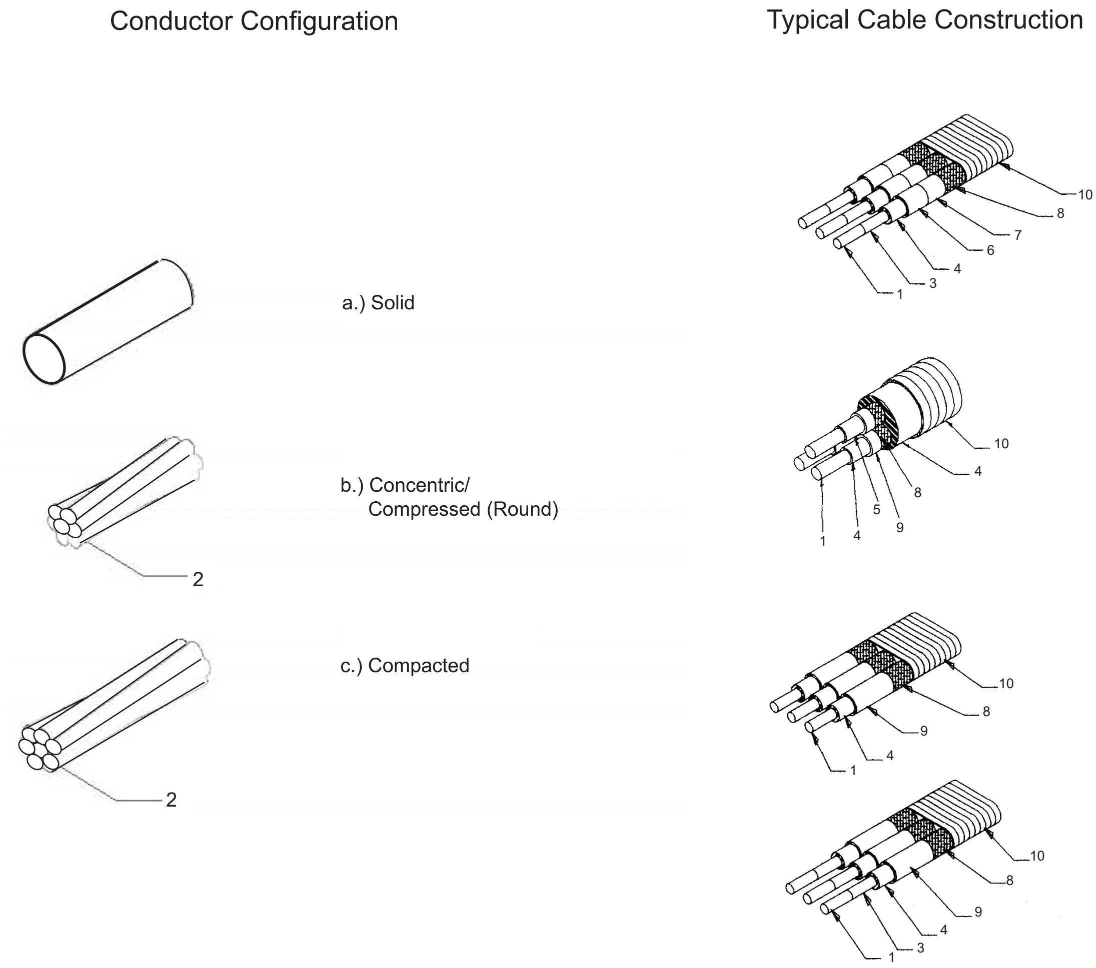

Figure Legend

Item	Description	Reference Section
1	Conductor	4
2	Strand Gas Block	4
3	Auxiliary (Secondary) Insulation	5
4	Basic Insulation	5
5	Physical Filler	Definitions
6	Jacket	6
7	Barrier Layer	7
8	Braid	7
9	Lead Sheath	7
10	Armor	8

Figure 3.1—Conductor Configuration and Typical Cell Construction

Table 4.1—Metric

Conductor Size	Conductor Area	Nominal Weight	Nominal Diameter of Conductor (mm)			Conductor Resistance (ohms/km @ 25 °C)	
	(mm^2)	(kg/km)	Solid	Stranded 7 wire	Compact 7 wire	Plain Copper	Tinned Copper
10 mm^2	10.0	88.5	3.57	—	—	1.87	1.88
6 AWG	13.3	118.0	4.11	—	—	1.32	1.36
16 mm^2	16.0	140.0	4.48	—	—	1.17	1.18
4 AWG	21.1	188.0	5.19	—	—	0.830	0.856
4 AWG	21.1	188.0	—	5.89	5.41	0.846	0.882
25 mm^2	25.0	222.0	5.64	—	—	0.742	0.749
2 AWG	33.6	306.0	6.54	—	—	0.522	0.538
2 AWG	33.6	306.0	—	7.42	6.81	0.531	0.554
1 AWG	42.4	386.0	7.35	—	—	0.413	0.426
1 AWG	42.4	386.0	—	8.33	7.57	0.423	0.440
1/0 AWG	53.5	475.0	—	9.35	8.56	0.335	0.348
2/0 AWG	67.4	599.0	—	10.80		0.266	0.276

Table 4.2—Inches

Conductor Size	Conductor Area	Nominal Weight	Nominal Diameter of Conductor (in.)			Conductor Resistance (ohms/kft @ 77 °F)	
	(cmil)	(lb/kft)	Solid	Stranded 7 wire	Compact 7 wire	Plain Copper	Tinned Copper
10 mm^2	19644	59.7	0.140	—	—	0.569	0.572
6 AWG	26240	79.4	0.162	—	—	0.403	0.414
16 mm^2	31109	95.6	0.178	—	—	0.357	0.360
4 AWG	41740	126.0	0.205	—	—	0.253	0.261
4 AWG	41740	126.0	—	0.232	0.213	0.258	0.263
25 mm^2	49305	149.2	0.222	—	—	0.226	0.228
2 AWG	66360	206.0	0.258	—	—	0.159	0.169
2 AWG	66360	206.0	—	0.292	0.268	0.162	0.174
1 AWG	83690	260.0	0.289	—	—	0.126	0.130
1 AWG	83690	260.0	—	0.328	0.298	0.129	0.134
1/0 AWG	105600	319.2	—	0.368	0.337	0.102	0.106
2/0 AWG	133100	402.7	—	0.414		0.081	0.084

For a given conductor size, increasing current will increase both the power losses and cable operating temperature. Increasing the conductor size for a given current will decrease the losses and operating temperature.

Electrical submersible pump (ESP) cables are manufactured with either stranded or solid conductors. Solid conductors have the smallest diameter. For the same AWG (mm^2) size, stranding increases conductor diameter and flexibility. Some studies have shown stranded cable is less susceptible to compressive damage. Stranding is more common in larger conductor sizes. Motor lead extensions are usually solid.

This API recommended practice describes only the most common ESP cable constructions. Other specialized ESP cable designs are available for unusual or particularly harsh applications. When unusually demanding applications are encountered, it is advisable to consult an experienced ESP Cable Applications Engineer to identify which specific “tailor made” design is most appropriate for the specific service conditions encountered.

Solid conductors reduce the flow path for gas migration and minimize hydrogen sulfide deterioration. “Concentric,” “Compressed,” or “Compacted” (see Figure 3.1) stranded conductors filled with a gas-blocking compound are an alternative approach to addressing these problems.

The diameters of stranded AWG wire sizes are defined as a concentric strand. Compressed stranded conductors have 97 % of the diameter of concentric stranded conductors. Compacted stranded conductors have 92 % of the diameter of concentric stranded conductors.

Solid conductors are the smallest of all conductor designs and will reduce the overall dimension of the cable. Regardless of design, all types of cable must meet the same circular mil area, see Table 1 and Table 2.

The best cable design to run in a well is the one that has the lowest lifetime cost, taking into consideration initial cost, handling costs (including inventory control), operating losses and expected run life of the cable based on field experience.

4.3 Limitations

The main disadvantage of using copper is that it is susceptible to damage by hydrogen sulfide (H_2S). This problem is overcome in high temperature applications by using a continuous lead sheath that completely covers the insulation.

Copper is subject to work hardening and great care should be taken to prevent nicks in the copper when removing insulation during splice preparation or when applying terminals or connectors.

5 Cable Insulation Systems

5.1 General

5.1.1 Description

Insulation isolates the electrical potential between conductors and other conducting materials. Insulation also minimizes leakage current from the conductors. Material composition will affect the thickness required to maintain electrical isolation.

5.1.2 Applications

Typical materials used in oil well submersible cables are thermoplastics like polypropylene and thermoset compounds like ethylene propylene diene monomer (EPDM).

Some cables use a composite insulation system comprised of a primary and secondary insulation. Films or thinly extruded materials are used as the secondary insulation. These materials have a high dielectric strength (volts/mil) for their thickness. As a system, the insulations provide a synergistic effect to improve electrical performance.

5.1.3 Limitations

Operation at elevated temperature will shorten the life of a cable. In general, cable life decreases exponentially as the temperature increases. A general definition of useful life is described by embrittlement (age hardening) of the insulation. Localized heating zones will exist near the pump and motor.

Cables with polyethylene or polypropylene thermoplastic insulation have a lower rated temperature than cables with thermoset insulation.

Pressure cycling and exposure to downhole chemicals cause other forms of insulation degradation. Insulation choice is also influenced by well environment, gas type and gas concentration.

The cable manufacturer should be consulted about running and operating temperature limitations of their cable. If the cable will be exposed to temperatures less than 0 °F, the manufacturer should be consulted about special handling procedures that may require pre-warming of the cable before it is run into the hole.

5.2 Thermoplastic

5.2.1 Description

A thermoplastic is a plastic material that may be shaped when heated to an elevated temperature and retains a well defined shape or form when cooled. On re-heating above its deformation temperature, the material will reshape/ reform when an outside force is applied. The deformation temperature decreases as the applied force increases. Typical thermoplastic materials include polyethylene and polypropylene.

5.2.2 Application

Polypropylene is a relatively inexpensive insulation material useable in low-temperature oil well environments. It is useful in the –30°F (ambient) to +205 °F (conductor) temperature range.

5.2.3 Limitations

The useful temperature range is under ideal conditions where there is no chemical attack or applied mechanical forces. Cables with polypropylene insulation should not be handled in ambient temperatures below –30 °F. Bending at lower temperatures may crack the insulation.

There are several detrimental well conditions that are known to affect polypropylene. Carbon dioxide at levels above 10 % initiates premature cracking. Light ends of crude oil and aromatic hydrocarbons lead to softening. External forces (cable clamps, tensile forces) applied on a cable operating near the upper temperature limit can lead to premature deformation.

Polypropylene is susceptible to accelerated aging from contact with copper metal. Special anti-aging materials are added to reduce this impact. Once these agents have been consumed, residual free copper ions will attack the polypropylene. Most manufacturers apply a tin or lead alloy coating to isolate the copper from the polypropylene.

After the cable has been flexed, polypropylene will allow gas to migrate between the conductor and insulation. For applications where gas migration would be a problem, a conductor/insulation gas blocking material must be applied.

5.3 Thermoset Materials

5.3.1 Description

A thermoset material is a material modified through a chemical reaction, which becomes permanently shaped when cured. Typical thermoset materials include ethylene propylene rubber (EPR) materials such as EPDM, ethylene propylene monomer (EPM), and cross-linked polyethylene (XLPE).

5.3.2 Application

For ESP cable, EPDM is the most commonly used thermoset material.

EPDM retains good flexibility at extremely low ambient temperature (–60 °F). EPDM has been found to be preferred in carbon dioxide (CO_2) environments and is resistant to many types of well treatments. EPDM materials are generally preferred in higher temperature oil well applications. Some compound formulations of EPDM are useful to conductor temperatures of 400 °F if properly constrained by the cable construction.

5.3.3 Limitations

EPDM materials swell in oil, but this characteristic can be reduced by proper formulation. EPDM is highly dependent on outer constraining coverings to retain its integrity.

5.4 Films/Tapes

5.4.1 Description

Films are generally thin tapes of materials applied directly over the conductor. The films are helically wrapped with an overlap and are heat sealed.

5.4.2 Applications

Films are typically used where high dielectric strength (volts per mil) is required with minimal thickness of insulation. The material is suitable for high temperature (450 ± °F) applications. The most common applications are motor lead (flat) extension and motor winding insulation.

5.4.3 Limitations

Polyimide films are chemically attacked by moisture, which significantly degrades insulation characteristics and mechanical strength. The use of films has to justify their added cost.

5.5 Extruded Secondary Insulations

5.5.1 Description

Several materials are currently being extruded as secondary insulation. Thermoplastic polyvinylidene fluoride (PVDF) and ethylene chlorotetrafluoroethylene (ECTFE) are used for temperatures up to 300 °F, and fluorinated ethylene propylene (FEP) is used for temperatures up to 400 °F.

5.5.2 Application

The materials are extruded directly over the conductor or over the insulation to provide added dielectric strength and chemical resistance. The material is less susceptible to damage from ingress of well fluids than the EPDM covering. Therefore, it provides greater protection and may extend the life of the cable. See 7.4 on extruded barrier coverings for additional information.

5.5.3 Limitations

A secondary insulation cannot operate as a single system. It must be used in combination with a primary thermoplastic or thermoset insulation to enhance electrical and mechanical properties.

There should be an expectation of improved performance to justify the additional cost of thermoplastic coverings. Special splicing techniques must be used when repairing or terminating the cable.

6 Jackets

6.1 Description

Jackets are protective coverings used to mechanically shield the insulation from the downhole environment.

The jacket materials protect the insulation from mechanical abuse associated with handling. Some jacketing material may provide secondary insulation.

6.2 Applications

A jacket's useful properties depend on the ambient temperature and well conditions. The temperature rating of the jacket material may limit the rated temperature of the cable.

Compounding can raise the upper temperature limit by adjusting the type of cure and antioxidants. For lower temperature limits, a plasticizer is added. These additions slightly affect other physical properties such as elongation, hardness, or tensile strength.

Currently two types of jackets dominate the submersible pump cable market. These are made of nitrile or EPDM. The EPDM will operate at higher temperatures than the nitrile but the nitrile is tougher and more oil resistant.

EPDM jackets may be compounded to improve oil swell resistance. Furthermore, EPDM is inherently better than nitrile for handling and installation at lower surface temperatures.

6.3 Limitations

Nitrile is limited to an operating temperature of approximately +280 °F, while EPDM has an approximate operating temperature of +400 °F. These limits influence the rated temperature of the cable.

Operation at elevated temperature may shorten the useful life of a cable. In general, cable life decreases exponentially as the temperature increases. A general definition of useful life is described by embrittlement (age hardening) of the jacket. Localized heating zones will exist near the pump and motor.

The jacket choice is also influenced by well environment, gas type and gas concentration. Some acids in high concentrations can cause polymer or nitrile jackets to become brittle. Other forms of jacket degradation are caused by pressure cycling and exposure to downhole chemicals. Before a cable is exposed to chemicals, the chemical supplier and cable manufacturer should be consulted about possible detrimental effects.

Armor and/or constraining layers are critical to the protection of the jacket. Particularly, EPDM tends to swell in the absence of armor. When a cable without armor protection is pulled or pressure cycled, the jacket may balloon and rupture due to absorbed oils and gases.

7 Braids and Coverings

7.1 General

7.1.1 Description

Braids and coverings are supplementary layers of material used to provide specific mechanical performance characteristics to the cable system.

7.1.2 Application

The braids and coverings are applied over the insulation and may be either inside or outside of the jacket. These materials provide additional strength and protection to the underlying cable components.

7.1.3 Limitations

These materials increase the cable diameter and their additional cost must be justified by an anticipated improvement in performance. They are also susceptible to deterioration from well fluids and conditions.

7.2 Braids

7.2.1 Description

A braid is a woven reinforcement layer of synthetic material applied over the insulated conductor. Braids vary in degree of coverage or openness.

The most common braid material is polyamide. A more exotic material such as PVDF or polyphenyline sulfide (PPS) may be used in cables operating in highly corrosive and/or high temperature applications.

7.2.2 Applications

The primary purpose of a braid is to provide additional hoop strength for the insulation during decompression of entrapped well gases. Decompression may occur when the well fluids are rapidly pumped off during start-up operations or when the cable is pulled out of the well.

A braid also provides construction integrity to hold oil resistant tapes in place over the insulation.

In round cables, the presence of a braid assists in the separation of the jacket from the insulation during cable termination or repair.

7.2.3 Limitations

The braid provides a possible path for migration of well fluids under some conditions. Escaping liquids and gases can interfere with splicing if it is done soon after the cable is pulled.

Less than full coverage braids may have a tendency to cut the underlying material during decompression.

Polyamide is susceptible to degradation when exposed to moisture at temperatures above 212 °F.

7.3 Barrier Tapes

7.3.1 Description

Barrier tapes are commonly applied directly over the insulation to provide an oil and chemical barrier. The tape is generally used in conjunction with an overlying braid. Barrier tapes are helically wrapped. Each successive wrap of tape is applied to overlap the previous layer by approximately 50 %.

The most common barrier tape materials are PVF tape and ethylene tetrafluoroethylene (ETFE). PVF is highly chemically resistant, but has a temperature limit of 300 °F. ETFE is less chemically resistant, but has higher temperature capabilities, up to 380 °F. However, there may be economic considerations in the choice of materials.

Tape thicknesses may vary. For a specific material, thicker tape provides better barrier properties.

7.3.2 Applications

The primary purpose of barrier tape is to protect the underlying materials. With polypropylene insulation, low molecular weight oil fractions (light ends) and gases may enter the insulation and soften the material. With EPDM insulation, the material is highly susceptible to oil absorption, causing it to swell and rupture. The presence of the barrier tape extends the life of the cable by retarding the ingress of fluids into the underlying materials.

Tape also provides additional hoop strength for the insulation during decompression of entrapped well gases.

7.3.3 Limitations

Barrier tapes add appreciably to the cost of the cable. The tapes are generally used in conjunction with an overlying braid covering.

7.4 Extruded Barrier Coverings

7.4.1 Description

Barriers can be extruded under the insulation to protect the copper conductors or as an extruded covering over the insulation in place of the tape and braid construction.

Several materials are currently being extruded as barriers. PVDF and ethylene chlorotetrafluoroethylene (ECTFE) are used where operating temperatures will not exceed 300 °F. FEP is used for temperatures up to 400 °F.

7.4.2 Application

The barrier is extruded over the insulation to provide chemical resistance, mechanical protection, decompression resistance, and electrical strength. When the barrier layer is extruded over the insulation, there are no gaps or seams as found with the conventional tape and braid design. See 5.5.2 for additional information.

7.4.3 Limitations

Extruded barriers are more costly and the improved performance should be weighed against the cost for additional coverage.

Special splicing techniques must be used when repairing or terminating the cable.

7.5 Lead Sheath

7.5.1 Description

A lead sheath or jacket is a continuous seamless covering over the insulated conductor.

The composition of the lead varies from one supplier to another. Alloyed lead metals containing copper, or cadmium and tin are utilized to maximize the chemical resistance and mechanical properties of the metallic sheath. Pure lead is never used.

The lead sheath covering is applied onto the cable via an extrusion process. The geometric shape of the lead covering may be round, square, or eight-sided.

7.5.2 Application

The seamless and continuous lead sheath provides an excellent gas and liquid barrier for the insulation. In wells with H_2S, lead provides an effective barrier to protect the copper conductor.

7.5.3 Limitations

Lead is a soft metal and can be easily damaged. The lead sheath can crack due to work hardening from bending.

The cables are very heavy and can pose handling difficulties. Special splicing techniques are required when working with these types of cables. The cost of lead sheathed cables is generally higher than conventional EPDM cables so there should be an anticipation of improved performance to justify the expense.

After lead-sheathed cable has been pulled three to five times, the sheath can potentially be damaged from handling and bending. The method of handling and the size of the sheave impact reusability. Cable geometry, configurations, and/or specific lead alloys are designed to increase cycle life.

Flat-grooved sheaves should be used when running parallel (flat) cables. Conformal-grooved sheaves should be used for round cables. Minimum sheave size should be 54 in. in diameter.

Voltages on the phase conductors induce circulating currents in the lead sheath. On long cables, these currents have the potential to cause corrosion of the lead. An electrical bonding connection between the individual sheaths must be incorporated in the bedding layer to greatly reduce these currents. This bonding connection must be applied properly to prevent damage to the lead. The bonding connector may be metal or a semi-conductive tape or thread.

7.6 Bedding Materials

7.6.1 Description

Bedding materials are required during the manufacture of lead-sheath cable to protect the lead surface from mechanical damage during armoring.

A typical bedding material is polyamide braid. Another material used is EPDM impregnated tape.

7.6.2 Application

The bedding provides some protection for the lead during pulling and running operations. Some bedding materials may fill small holes in the lead extrusion. The bedding material also provides additional hoop strength if gases penetrate the lead. An electrical bonding connection is contained in the bedding material to prevent circular currents.

7.6.3 Limitations

EPDM swells when exposed to oil. A polyamide decomposes and loses strength in high moisture environments at temperatures over 212 °F. Neither of these limitations are critical to the application of the cable as long as the armor is intact.

The cycle life of cable may be shortened if the bedding materials deteriorate. Loss of these materials allows the armor to come in contact with the lead.

8 Armor

8.1 General

8.1.1 Description

Armor is the outer covering that provides mechanical protection during installation and removal of cable. The armor in round cable also provides mechanical constraint against swelling or expansion of underlying elastomeric materials on exposure to well fluids.

Armor may provide some of the longitudinal support for the weight of the cable between bands.

The armor configuration may be either flat or interlocked metal strips. Some designs use two layers of armor and a special design uses helically applied round wires.

Armor material usually consists of galvanized steel. For some environments, stainless steel or stainless steel metal alloy is used.

8.1.2 Application

Armor is used in applications where jacket materials do not provide adequate mechanical protection for the cable.

Flat armor is used where the overall clearance for the cable is restricted.

Interlocked armor is used to minimize the tendency of the armor to unravel. Furthermore, it is less likely to snag during running and pulling.

Helically applied round wires are used where the armor is required to provide most of the longitudinal strength of the cable, such as where there are long distances between bands. This type of armor is used in submarine cables and some large wellbore applications.

Armor provides strength to maintain cable integrity while hanging in the well. Bands or clamps are used to attach the cable to the tubing and provide support.

Normal industry practice is to put one band in the middle of a joint of tubing and a second band just above the coupling. These bands support the weight of the cable.

8.1.3 Limitations

The integrity of the armor is influenced by the environment in which it operates. Corrosion is one of the major factors that influences the choice of materials.

For very severe applications and where cost can be justified, stainless steel metal alloy armor can be used to withstand the most corrosive conditions. Stainless steel armor, though not as effective, is a lower-cost alternative to stainless steel metal alloy.

Helically applied flat armor has one edge exposed. Therefore the cable should be installed so the exposed edge is toward the top of the well. This reduces the risk of snagging the armor during installation.

8.2 Galvanized Steel

8.2.1 Description

Galvanized steel armor is constructed from low carbon (mild) steel that has been zinc-coated on all sides. Galvanized steel armor can be provided in 15 mil, 20 mil, 25 mil and 34 mil thickness. The zinc coating can be applied in various weights based on ASTM A459. Class I coatings have 0.35 oz/ft^2 (110 g/m^2), Class II 0.70 oz/ft^2 (210 g/m^2) and Class III 1.0 oz/ft^2 (300 g/m^2). Class III is not recommended because it can flake off, creating concentrated corrosion cells.

8.2.2 Applications

Most well environments permit the use of galvanized steel armor. It can be provided in a double layer to provide longer protection against corrosion.

8.2.3 Limitations

Galvanized steel is susceptible to corrosion in the presence of H_2S, CO_2, strong acids, alkaline environments, as well as brines.

The corrosion problem becomes more intense as temperature rises.

Typically, adding additional zinc coating will not appreciably extend the armor life in a corrosive environment. It is usually more beneficial to increase the thickness of the steel or use more corrosion resistant material.

For some cable suspended systems, it may be necessary to use either a high strength steel or stainless steel round wire to provide the required longitudinal strength.

Due to the magnetic characteristics of ferrous metals, there will be increased electrical power losses in the cable. This is the result of hysteresis and eddy currents induced in the steel by current in the conductor. The effect is more significant in flat cables with unbalanced phase currents.

8.3 Stainless Steel

8.3.1 Description

Stainless steel is a class of steels containing a significant quantity of chromium, in conjunction with other alloys. Stainless steel armor can be provided in 15 mil, 20 mil, and 25 mil thickness.

The predominant grades of stainless steel used for cable armor are 316L and 409.

8.3.2 Applications

Stainless steel armors are used in corrosive environments. Although there are limitations, stainless steel may still be selected over more expensive alternatives.

8.3.3 Limitations

Where chloride ions are present, pitting may occur in stainless steels. Stress corrosion cracking (hydrogen embrittlement) of 300 series stainless may occur in this environment at temperatures greater than 160 °F.

Neither 409 nor 316L stainless steel is recommended for H_2S applications. CO_2 environments can also affect the 400 series stainless steels. The 400 series can be used in wells with up to 10 % CO_2 and pressures of 3000 psi. The 400 series stainless steels should not be used in environments where oxygen is present.

8.4 Stainless Steel Metal Alloys

8.4.1 Description

Stainless steel metal alloys with a content of greater than 60 % nickel, less than 4 % iron, 2 % manganese, and the remainder copper can be provided in 15 mil and 20 mil thickness.

8.4.2 Applications

This alloy is used in the most severe environments. Some of these include CO_2, H_2S, and high temperature (> 160 °F) brine solutions.

8.4.3 Limitations

The value of improved performance should be weighed against the cost of using a premium metal for armor protection.

9 Auxiliary Cable Components

Auxiliary equipment is used in conjunction with the cable for specific operating needs. For special applications or equipment configurations, design should be referred to the equipment manufacturer.

9.1 Downhole Monitoring Sensor

To get a more accurate description of downhole conditions at the pump, there is a variety of sensor packages and installation methods available. Pressure (intake/discharge), temperature (fluid/motor winding), current leakage, flow rate, dielectric strength of motor oil and vibration are parameters that can be measured with downhole sensors. The downhole sensor transmits the data to surface through a dedicated line, an embedded separate conductor in the power cable or as a signal that is transmitted up a conductor of the power cable.

9.2 Backspin Relay

A backspin relay can be located in the controller to monitor the current flow through the cable when the pump is spinning backwards as fluid flows through the pump from the tubing when the hydrostatic head in the tubing is greater than the bottomhole pressure. This relay prevents startup until the pump is no longer spinning. This is a safety device that prevents the pump from starting up under conditions that could lead to shaft failure or a cable or motor burn.

9.3 Cable Bands or Clamps

Cable bands or clamps are used to attach the power cable to the outside of the tubing string because the cable cannot support its own weight. For most applications, cable bands made of carbon steel, stainless steel or stainless steel metal alloys are used. The minimum banding recommendation is two bands per tubing joint, with one band in the middle of the joint and the other band two to three feet above the collar. The bands are available in different widths with wider bands used with heavier cable (e.g. lead lined cable).

When an installation presents the possibility of cable damage, such as deviated wellbores, special equipment should be considered. Reuseable over the coupling protectors (cable clamps or protectolizers) are designed to prevent the power cable from making contact with the well casing while securely fastening the cable to prevent it from slipping. Reusable bolting or pin clamps are also available for installation in the middle of the tubing joint if additional support or protection is necessary.

9.4 Cable Deployed Pumping Systems

A tension cable is used for cable deployed ESP systems. The specially designed tension cable, which must support the weight of the downhole equipment, is used to raise and lower the ESP system in and out of a seating or landing nipple in the wellbore. The cable-deployed system requires special handling equipment and is typically cost competitive only under unusual operating conditions. The tension cable termination point, called the rope socket, is a weak point of the system (due to the use of shear pins) to enable recovery of the cable if the ESP becomes stuck in the landing nipple.

9.5 Coiled Tubing Deployed Systems

Coiled tubing is used to supply strength to run, set and operate coiled tubing deployed ESP systems. There are several configurations depending on whether the power cable is banded external to the tubing or placed inside the coiled tubing. Only the internal power coil system allows the possibility of workovers on a live well using a lubricator and stripper for control.

10 Splicing and Terminating

10.1 General

10.1.1 Description

Splicing and terminating are the transitions from one cable to another cable or to a connection. Splicing and terminating must provide electrical, mechanical, and environmental integrity.

10.1.2 Application

Splices are used when individual cable lengths are too short for the application or when cables with different geometries need to be run. Terminations are used when the cable must be connected to other equipment.

10.1.3 Limitations

The diameter of field splices and terminations will be larger than the cable itself. The voltage stresses tend to be concentrated at the transition areas around the conductor connectors.

10.2 Factory Repairs

10.2.1 Description

A factory repair is the minor correction to insulation, jacketing, armoring, or lead during manufacturing. It does not involve the conductor.

10.2.2 Application

Factory repairs enable the manufacturer to effectively correct flaws or other imperfections in the cable without compromising the end performance of the cable. The finished, repaired cable should be tested to new cable specifications.

10.2.3 Limitations

Manufactured cables that are repair-free may be preferred to repaired cable.

10.3 Factory Single Conductor Lengthening

10.3.1 Description

Factory single conductor lengthening is the joining of two insulated lengths of single conductors during the manufacturing process.

10.3.2 Application

Occasionally it may be necessary to extend the length of one or more conductors to achieve the desired assembly length. This lengthening is done by butt welding the conductors and re-insulating the section. For stranded cable, each strand must be individually butt welded in a staggered pattern. The finished, lengthened conductor should be tested, in the same manner as an unlengthened conductor.

10.3.3 Limitations

The customer should be made aware of any lengthening by the manufacturer. Manufactured cables that have not been lengthened may be preferred to those containing joined conductors.

10.4 Splices

10.4.1 Description

A splice is the joining of two individual cables. This involves complete cable assemblies, which includes conductors, insulation, sheathing, jacketing, and armor as applicable.

10.4.1.1 Conductor Joining

The most common way of joining conductors uses crimped connectors. An alternate method for solid conductors is butt welding.

10.4.1.2 Insulation and Jacket Replacement

The three fundamental replacement methods are molded, vulcanized, and tape-wrapped.

A molded splice uses thermoplastic material for the insulation. This is accomplished in a heated, injection-molding press.

A vulcanized splice uses curable, thermosetting tapes for the insulation and/or the jacket. The process is completed in a heated mold.

A tape-wrapped splice may use thermoplastic, cured, uncured, or low-temperature curable tapes for the insulation and/or the jacket. No additional processing is required.

10.4.1.3 Metallic Coverings

For lead-sheathed cable, a sheet of lead is wrapped around the insulation and overlaps the existing lead sheathing. The sheet is either soldered or taped in place. However, it should be assumed that gas will migrate through taped joints.

Replacement armor is helically applied over the entire splice. The ends are then soldered to the existing armor.

10.4.2 Application

A cable splice may be used to lengthen the cable string, to repair failed or damaged cable, to join the motor flat cable to the main cable, to join the main cable to the pigtail, or to make a transition between different cable types or sizes.

The connection of the conductors provides electrical continuity.

Insulating material is applied over the connection to provide voltage isolation. Additional materials are added to protect the electrical insulating material from well conditions. The integrity of the insulating material will impact the transfer of gases through the cable.

The metal coverings over the cable provide mechanical and environmental integrity.

10.4.3 Limitations

The properly trained cable splicer must deal with many variables that can affect the quality of work being performed. The quality of the splice is influenced by weather conditions, the conditions of the available work area, pressure to finish the job quickly, and skill level of the splicer.

Molded and vulcanized splices generally provide better integrity. However, they do require more time to make than taped slices.

Whenever possible, splices should be kept above the operating fluid level.

Splice-free cables are preferred to those containing splices. Reuse of cables with splices and the number of splices in the string increases the probability of cable failure.

10.5 Terminations

10.5.1 Description

Power cables are terminated at each end using either connectors or penetrators.

10.5.2 Application

Terminations are located at most wellheads, at the submersible motor, and at some downhole packers. Wellhead and packer terminations that use a short piece of cable are referred to as “pigtails.”

Motor terminations are referred to as “potheads.” A pothead is usually supplied as part of a motor lead assembly that is spliced to the main power cable. The pothead may be installed directly on the power cable when the space between the motor and casing permits.

A “pigtail” is a length of cable that is spliced onto the main power cable. Another type is an attachable termination, which is installed directly on the power cable.

10.5.3 Limitations

Available space in the wellhead dictates the size and type of termination. The wellhead manufacturer’s recommendations should be followed.

Termination materials must be compatible with the main cable for conductor size and metallurgy, temperature rating, and insulation types to ensure the longest possible life. The materials must also be compatible with the well fluids and conditions.

Wells containing H_2S or CO_2 require the same special considerations in the selection of termination materials as previously noted for cable components. The more terminations there are, the greater the chances of a failure.

10.6 Typical Cable Splice

10.6.1 The following diagrams provide a representation of a typical cable splice. This is not intended to limit or restrict alternative configurations.

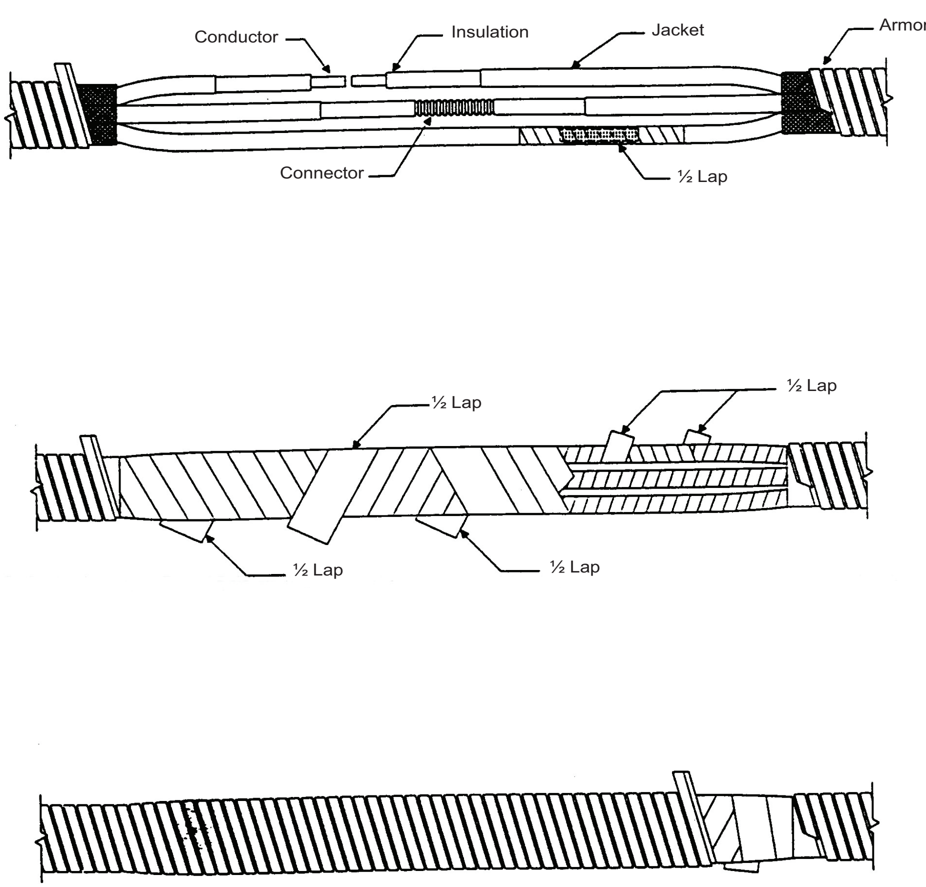

Figure 10.1—Typical Cable Splice

Annex A

Power Cost Considerations

A.1 Introduction

Once the horsepower requirements for an ESP have been determined, several items must be considered to achieve minimum overall costs from the cable system. These considerations are size of cable, voltage requirements and current requirements.

A.2 Voltage/Current

Power used by an electrical submersible motor is related to the motor current through the cable and to the motor voltage. Since the required power remains relatively constant, higher system voltages will result in lower motor current. Power losses in the cable are equal to the product of cable resistance, number of conductors, and current squared. Higher voltage, lower current motors reduce power losses for a fixed conductor size.

The NFPA 70 (*National Electric Code*) suggests that a maximum cable voltage drop of 5 % of motor nameplate voltage will provide reasonable efficiency.

A.3 Conductor Size

Although numerous conductor sizes have been used, the industry has essentially standardized on No. 4 AWG, No. 2 AWG, No. 1 AWG, No. 1/0 AWG and No. 2/0 AWG for the main feeder to the electrical submersible motor. No.6 AWG wire is available for applications with lower power requirements.

Provided there is adequate clearance in the well bore, the selection of the electrical conductor size is based on the amount of current the conductor must carry.

An economic analysis should be performed to evaluate whether lower power costs over the life of the cable will offset the higher initial purchase price of a cable with larger conductors.

A.4 Analysis Method

The basic equation for calculating current when sizing a cable is given below. Additional information will be required from other sources to provide a complete analysis (e.g. including the impact of incorporating power factor in the design).

$$I = \left(k \times \frac{CD}{RD} \times PC \times Ph \times ECL\right)^{0.5}$$

where

I is the load current value above which a larger conductor size can be justified (amperes);

k is the constant = 0.114;

= 1000 [*Wh*/*kWh*] / 24 [hr/day] / 365 [days/year];

CD is the cost difference between two cables using different conductor sizes [$/1000 ft];

RD is the difference in resistance between two conductor sizes at the bottom hole temperature of the well;

PC is the electric power cost [$/*kWh*];

Ph is the number of phases = 3;

ECL is the estimated cable life (years). The number of years required for an investment payout could be used in lieu of cable life.

Annex B

Cable Selection Guide

B.1 Introduction

This annex correlates the various components of a cable with the operating conditions to which it may be exposed. The guide is grouped by sections corresponding to the cable construction. References are given to other documents for additional information that is not identified in this recommended practice.

B.2 Temperature Designation

Four general categories are listed in this appendix. They are differentiated by the maximum operating temperature to which the cable is subjected. This temperature is a function of the ambient temperature and the temperature rise caused by current flow and mechanical operations. The conditions are listed as (**L**)ow, (**M**)edium, (**H**)igh and (**S**)evere.

Table B.1—Temperature Rating (Section 3.2)

Temperature Designation	**L**	**M**	**H**	**S**
Material that Determines Rating	Polypropylene	Nitrile	EPDM	Lead*
Maximum Conductor Temp (°F)	205	225 – 280**	400	450
	* Lead sheath over elastomers or other special construction ** Maximum temperature depends on formulation			

Table B.2—Conductor (Section 4)

Temperature Designation	**L**	**M**	**H**	**S**
Material	Copper	Copper	Copper	Copper
Coating	Tinned	Untinned/Tinned		
Metal Properties	*NEMA WC-Code*, ASTM B3, B8, B33			
Specifications for Dimensions	Table 4.1 or Table 4.2 as applicable			
Type	Solid, Stranded, Compacted			
Size (AWG/M)	6, 4, 2, 1, 1/0, 2/0 / 10, 16, 25 mm			

Table B.3—Insulation (Section 5)

Temperature Designation	**L**	**M**	**H**	**S**
Material	Polypropylene	EPDM	EPDM	EPDM
Tests	IEEE 1019	IEEE 1018		
Properties	IEEE 1019	IEEE 1018		
Dimensions	IEEE 1019	IEEE 1018		
Over Conductor Films	Use as Needed for Increased Dielectric Strength.			

Table B.4—Jacket (Section 6)

Temperature Designation	**L**	**M**	**H**	**S**
Material	Nitrile	Nitrile	EPDM	EPDM
Tests	IEEE 1019	IEEE1018		
Properties	IEEE 1019	IEEE1018		
Dimensions	IEEE 1019	IEEE1018		

Table B.5—Braids and Coverings (Section 7)

Temperature Designation	**L**	**M**	**H**	**S**
Braids	Polyamide	Polyamide	Polyester/PPS/ETFE	
Alternative Braid	—	PVDF	—	—
Sheath	—	—	—	Lead
Barrier Material	PVF/PVDF			
Bedding	—	—	—	Polyamide/EPDM
NOTE Braids and coverings are optional and subject to wide variations among manufacturers. These are the most widely used types.				

Table B.6—Armor (Section 8)

Temperature Designation	**L**	**M**	**H**	**S**
Standard	Galvanized Steel			
Special Construction	—	—	Double Galvanized	
Corrosion Resistant	Stainless Steel Alloys			
Dimensions	IEEE 1019	IEEE 1018		

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